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Cogeneration of Electricity and Heat from Biogas

A Subcontract Report

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R. K. Koelsch
R. J. Cummings

Prepared under Subcontract No. XB-0-90-38-1

Solar Energy Research Institute
A Division of Midwest Research Institute
1617 Cole Boulevard
Golden, Colorado 80401-3393

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SERI

FOREWORD

Biogas generation from anaerobic digestion of agricultural wastes and other organic matter is now a commercial reality. Several hundred farms in the United States and Europe produce biogas in significant quantities. Because of its nature, methane, the major component of biogas, can be used in many energy systems. Electricity and hot water production using a biogas-fueled internal combustion engine to power an electrical generator is known as cogeneration. Biogas production systems can be designed and costed with minimum risk using existing information. However, biogas conversion to useful forms of energy remains poorly defined, especially in relation to cogeneration. This study was conducted to expand the information on the cogeneration alternatives for application to small farms at a 25 kW capacity size.

This work was performed under SERI subcontract XB-0-90-38-1 with funds provided by the Biomass Energy Technology Division of the U.S. Department of Energy, Dr. Beverly J. Berger, Director.

Michael Z. Lowenstein
Biofuels Program Office

Approved for

SOLAR ENERGY RESEARCH INSTITUTE

Eric Dunlop, Director
Solar Fuels Research Division

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Other Cornell staff who contributed to the design and operation of the project included C. E. Harrison, R. W. Guest and J. A. Metzger. M. Baird and others provided part-time assistance. We also acknowledge assistance from H. L. Fries, J. Connors of Cummins-Mohawk Company, the National Seal Company, and Kendall Refining Company. Cummins-Mohawk Company of Syracuse, New York, provided technical assistance when problems occurred with the cogeneration unit.

SUMMARY

COGENERATION OF ELECTRICITY AND HEAT FROM BIOGAS

INTRODUCTION

Biogas production from animal manures is becoming more well defined and popular. The ultimate value of the production of biogas by anaerobic digestion depends on the extent to which existing farm fuels can be replaced. The goal of this study was to document at full scale biogas conversion to electricity and heat energy in a custom-designed cogeneration internal combustion engine facility.

OBJECTIVES

The specific objectives of this project were to:

1. continue to document the operational characteristics of two full scale 65-cow manure digesters (the completely mixed control design and the low cost plug flow design) in their fifth and sixth years of operation; and to

2. define the characteristics, long term reliability, and efficiency of a cogeneration facility using a self-paralleling, single-phase induction generator with waste heat recovery from the internal combustion engine.

BACKGROUND

A seven-year team effort at Cornell University sponsored by the U.S. Department of Energy resulted in a low cost design alternative for dairy manure digestion that appeared to provide energy at a competitive cost on small farms. The low cost unit was operated in parallel with a more complex completely mixed control reactor for the past five years under "real world" cold climate conditions. A complete gas storage and utilization system was installed in the spring of 1981. This report covers a two year operating period and represents one of the first comprehensive evaluations of cogeneration at small farm scale.

Cogeneration is recognized as an efficient use of energy resources. It is anticipated that 10,000 megawatts of electricity will be produced by 1990, and half of this will be powered by natural gas driven engines. The technology is presently well-defined for large installations. Relatively little is known about the technology as it applies to installations of less than 100 kW capacity operated on biogas with large quantities of carbon dioxide, and contaminated with water, hydrogen sulfide, and other trace materials (ammonia, hydrogen, etc.).

EXPERIMENTAL APPROACH

Many of the components of farm scale biogas production, storage and utilization were tested at full scale in this study. The two digesters (completely mixed and a plug flow unit) produced a total of around 142 m^3/d (5,000 ft^3/d) of biogas. Three alternate gas storage/usage systems were tested—direct storage in a low pressure, flexible pillow tank (at 7.5 cm of water pressure), storage at intermediate pressures at 14 kg/cm^2 (200 lbs/in^2), or the biogas was blown directly to the engine for combustion. The cogeneration unit consisted of a 25 kW single phase induction generator powered by a White industrial 4 cylinder spark-ignited engine. The study examined the entire system but emphasized the engine generator set electrical efficiency, generator power factor, engine fuel consumption, impact of compression ratio variation, waste heat recovery efficiency, and interconnection of generator with utility.

RESULTS

The digesters continued to process cow manure without problems, achieving greater than 80 percent conversion of the biodegradable organics under most conditions. The plug flow unit continued to be a simpler and more efficient system than the completely mixed alternative. Eight loading conditions were documented. However, since the biogas production capacity limited cogeneration operation to about 10 hours per day, efforts to increase biogas production were made. Two major design changes were implemented—the plug flow unit was more than doubled in capacity (reactor volume increase from 40 m^3 to 93.5 m^3), and the entire facility was converted to a two-stage series system with the plug flow unit receiving the effluent from the completely mixed unit. Total gas production exceeded 440 m^3/d with the system during high rate loading conditions, thus enabling full time operation of the cogeneration system.

Initial operation of the cogenerator resulted in misfiring and general rough operation, but proper selection of spark timing and fuel-air mixtures resulted in smooth and efficient operation. When properly timed and operated under design load, 26 percent of the biogas energy was converted to electrical energy, and 45 percent of the heat energy was recovered in hot water, making a total potential energy recovery of 71 percent. Improper fuel-air mixtures reduced electrical conversion to less than 18 percent and heat recovery to 32 percent.

Comprehensive testing of the cogeneration unit documented the effects of carburetion, ignition, and electrical loads on the cogeneration system performance. The induction generator and the simple electrical switch gear that enabled it to feed power into the utility mains proved reliable and efficient. The characterization of the system should be useful in other induction cogeneration systems.

Much of the attention was focused on engine wear and maintenance problems associated with biogas use. Extensive monitoring and testing of lubrication oil was conducted. The 2500+ hours of operating time on the system was divided equally between the use of raw biogas (initially) and biogas that was filtered for the removal of mercaptans and water.

The biogas contained surprisingly high hydrogen sulfide levels, with most values exceeding 3,000 ppm. Sewage biogas usually contains less than 200 ppm, other dairy digesters have reported less than 1,000 ppm, and engine manufacturers suggest using gaseous fuels with less than 1,000 ppm H_2S. It was anticipated that use of highly buffered oils (oils with total base numbers as high as 10) would protect engine components. Engine oil changes were made upon the recommendation of the oil company, and often at intervals less than 100 hours. This conservative approach did not provide sufficient engine protection.

Two major engine failures occurred during the study--after 193 hours of operation the unit severely overheated and destroyed much of the engine (this resulted from a malfunctioning overheat switch); and after 2,530 hours a rod was thrown through the side of the engine block. After the first failure the engine was rebuilt and operated for 1,200 hours on raw biogas. A complete engine disassembly at this point revealed some unusual wear, including moderate pitting of the rod bearing surface.

After the rod failure the sulfur filter was examined and the engine was disassembled and examined by the suppliers and the engine manufacturer. Although the sulfur filter was considered to have remaining removal capacity, the engine had experienced considerable wear. This was at less than 15 percent of the desired time between major engine overhauls, and less than 3 percent of a desirable system lifetime.

Although this experiment represents the result of testing with only one engine, the general interaction with the equipment, suppliers, and the manufacturers point towards some directions for the technology. Most important is an extensive protection package for unattended safe operation of such systems. The second general conclusion relates to the usefulness of oil TBN as an indicator of engine protection. Additional work is needed in this area.

In conclusion, this study confirms that cost-effective and reliable biogas production can be achieved on dairy operations. Additional work is needed to predict and control biogas contaminants that adversely affect conversion processes.

The cogeneration technology is well developed and predictable. However, small scale cogeneration packages (with capacities less than 100 kW) have not reached the maturity needed to support their widespread installation. More reliable engine controls and safety features must be built into cogeneration packages. Procedures for minimizing biogas contaminants such as hydrogen sulfide effects on engine components must be identified. Finally, methods of real time monitoring of cogeneration systems need to be improved.

CHAPTER I

INTRODUCTION

Biogas generation from anaerobic digestion of agricultural wastes and other organic matter is now a commercial reality. Several hundred farms in the United States and Europe produce biogas in significant quantities. Because of the nature of methane, the major component of biogas, it can be used in many energy systems. Electricity and hot water production using an internal combustion engine to power an electrical generator is one biogas use alternative. It is known as cogeneration. Information to design anaerobic digesters and suggestions to use cogeneration can be found in many references (Northeast Regional Agricultural Engineering Service, 1981; Persson, et al., 1979; National Center for Appropriate Technology, 1984; Palmer, 1981). Biogas production systems can be designed and costed with a minimum risk using existing information. However, biogas conversion to useful forms of energy remains poorly defined, especially in relation to cogeneration. This study was conducted to expand the information on the cogeneration alternatives for application to small farms at a 25 kW capacity size.

I.A. GOALS AND OBJECTIVES

The goals of this project were twofold: to document the feasibility of using small scale cogeneration on farms, and to continue to develop long-term operational information on two full scale dairy manure digestion systems.

The specific objectives of this project were to:

1. develop long-term reliability information for dairy manure digestion in the two major designs: full scale completely mixed and plug flow reactors;

2. monitor and document the performance of the internal combustion engine-electrical generator unit at varying electrical outputs and fuel-air mixtures;

3. determine the thermal energy recovery performance of the engine's heat exchangers;

4. determine the feasibility of using higher compression ratios to increase engine efficiency;

5. define the long-term reliability of the cogeneration system on biogas; and

6. monitor the ability of the induction generator to transfer acceptable electricity to the utility.

I.B. BACKGROUND

I.B.1. Farm-Scale Cogeneration

Cogeneration, electricity generation along with waste heat recovery, is a concept that is presently widely recognized as an efficient use of energy resources. The passage of the national Public Utility Regulatory Act (PURPA) of 1978 provided an incentive for the implementation of cogeneration, especially in instances where the heat could be put to good use. This law provided for fair and reasonable treatment of cogenerators wishing to sell electricity while having a standby, backup source of power. The law exempts cogenerators from utility regulation and provides for the sale of cogenerated electricity to the utilities at the utilities' "avoided" cost. This law applies to small power producers at facilities generating less than 80 megawatts of electric power and which employ renewable resources such as water, wind, solar energy, or biomass.

It is anticipated that 5,000 megawatts of cogeneration capacity will be installed by 1990, thus doubling the present cogeneration capacity (Williams, 1982). Half of the expected added capacity will be powered by natural gas.

A review of the energy balances on farms showed that biogas production from wastes could displace most conventional fuels (Jewell *et al.*, 1976). This general relationship also applies to cogeneration. The average electrical usage on dairy farms in Pennsylvania was reported to be 1.7 kilowatt-hours per cow per day and ranged from 1.4 to 2.0 kilowatt-hours per cow per day, depending on the type of animal nutrition and anaerobic digester design. Installation of cogeneration on dairies alone in the United States would account for greater than 1000 megawatts generation capacity and equal more than 20 percent of the expected growth in cogeneration over the next five years.

I.B.2. Potential Energy Replacement on Dairy Farms

A dairy operation is primarily dependent upon liquid fuels and electricity to supply its energy needs. An analysis of the energy use for a 100-cow dairy (Figure 1.1) revealed that liquid fuels and electricity account for 82% and 17%, respectively, of the total farm's energy demands (Williams *et al.*, 1975). More than a third of the energy consumption of this dairy is for stationary applications. All of the energy needs of the farm except electricity show major variations in seasonal use. Heating oil needs peak in the winter while gasoline and diesel fuel are in greatest demand in the summer.

The efficient utilization of biogas from an on-farm anaerobic digester remains a major obstacle to implementation of the technology on livestock farms. The heavy reliance of many livestock farms on electrical and heat energy needs makes cogeneration a potential option. However, the wide variation in daily electrical and seasonal heat energy needs presents special problems for an on-farm cogenerator.

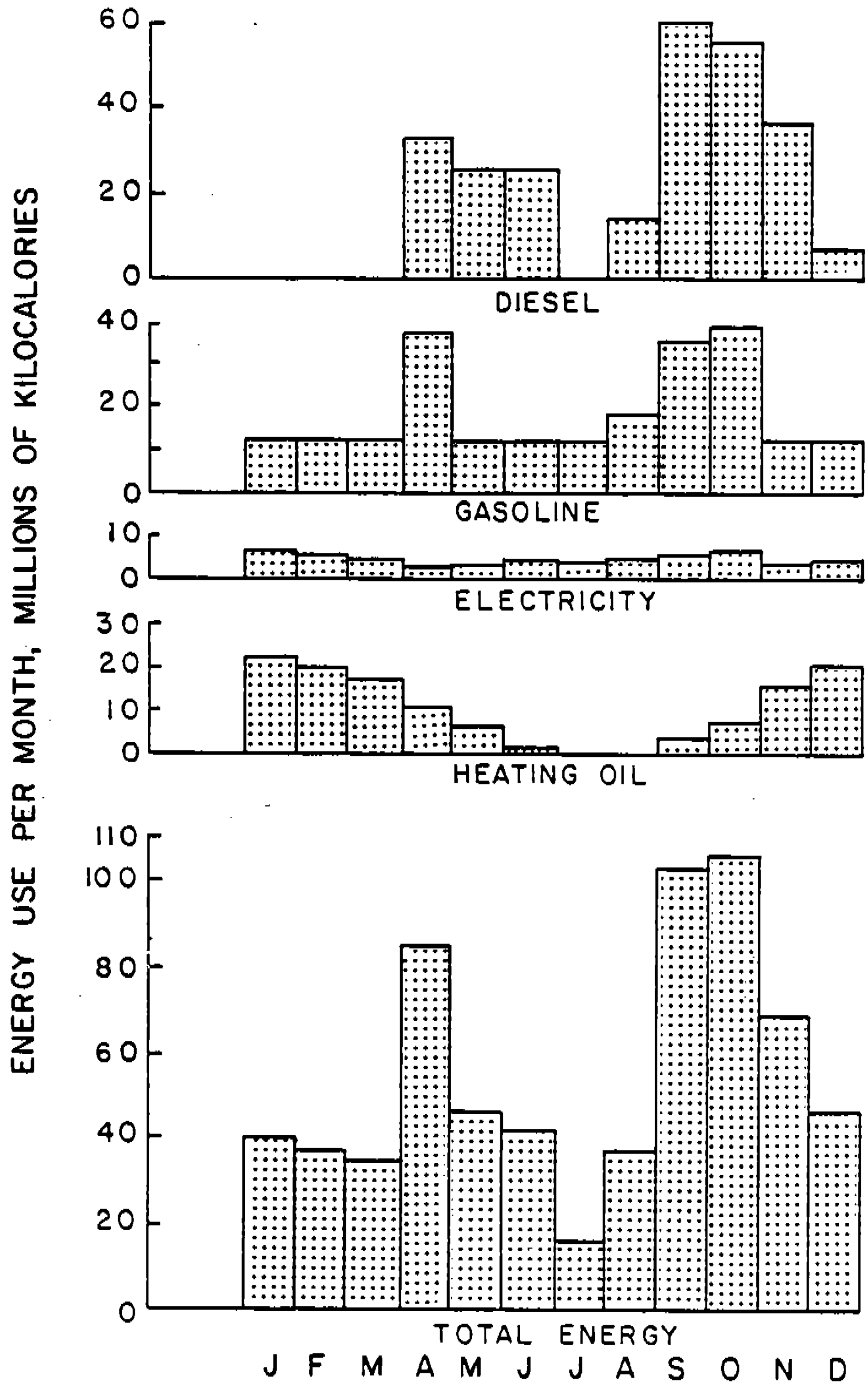


Figure 1.1. Monthly energy consumption by type of fuel - 100-head dairy.

Presently, three alternatives exist for the utilization of the gas: (1) replacement of liquid fuels for mobile application; (2) direct combustion of the gas for space heating and water heating; (3) cogeneration of electricity and heat for space heating or water heating.

The option of using the biogas for heating purposes could be applied to home space heating and water heating with few if any technical problems. Recent innovations in the dairy industry, including detergents requiring low temperature water (36°C+) and refrigeration heat recovery units will lower the need for any energy purchases for heating in the dairy (Koelsch, 1980; Weeks, 1981). These measures are economically very attractive and becoming commonly accepted with the dairy industry. Thus, biogas will have application to home space and water heating only. The potential energy replacement for several dairies has been reviewed (Koelsch, 1981), and it would appear that the quantity of the energy replaced, especially on the larger dairies, is very small in relation to the total potential biogas production. Biogas utilization for direct heating purposes appears to be an attractive alternative for a smaller dairy only.

The generation of electricity and hot water by means of an engine generator set appears to hold more promise than the two previous alternatives, especially for larger dairies. Dairies as small as 80 cows could supply enough biogas energy to operate a 10 kW generator continuously, the smallest generally available water cooled engine generator set. Smaller dairies would be forced to operate a generator intermittently and provide gas storage during the down periods.

Standard equipment available through engine generator supplies and manufacturers should be able to recover 20% of the biogas energy as electricity and 50% of the biogas energy as hot water. With recovery rates of this magnitude, the energy replaced on dairies is summarized in Table 1.1. By cogeneration, the biogas energy that is recovered has increased dramatically, especially on the larger dairies. The total dollar value of our on-farm anaerobic digester has also increased. If cogeneration can be accomplished without major increases in capital and operating costs or farmer inconvenience, it appears to hold considerable advantage over other alternatives.

I.B.3. Biogas as an Engine Fuel

Methane has been described as the fuel for the future (McGeer and Durbin, 1982). Reviewing the benefits versus the disadvantages of using methane as an engine fuel, McGear and Durbin (1982) have said that "it is not a substitute fuel; it is a superior fuel." Methane gas has an octane number of 120, and when diluted by the carbon dioxide contained in biogas it still has an octane of greater than 100, which is far above the 89 octane gasoline now in use. The fuel use efficiency is related to the octane number, thus indicating that biogas could be more efficient than gasoline. Over 1,000,000 miles of existing natural gas pipeline deliver this fuel to the majority of homes in the U.S. This in-place delivery system could be utilized to support numerous alternatives. It is environmentally safe. We have long-term experience with it since many of us burn it in open flames in our kitchens. It prolongs the life of engines by not diluting the oil. Since it is a gas, even at low temperatures it makes winter engine starting easier. It has a high ignition temperature and a narrow inflammability limit. Consequently, it is a lesser fire and explosion hazard than gasoline. Methane is also lighter than air; and unlike propane, which puddles when released, it rises quickly and disperses when it escapes.

TABLE 1.1. ANNUAL ENERGY REPLACED ON SEVERAL DAIRIES BY USE OF BIOGAS IN COGENERATION

	50 Cows	100 Cows	300 Cows
Home heating needs replaced (GJ)[1]	122	184.4	394.8
% of farm heat needs replaced	62%	94%	100%
Electrical energy produced in GJ (kWh)[2]	135 (37400)	270 (74900)	809 (224,600)
% of biogas energy recovered[3]	38%	34%	30%
Value of farm energy replaced[4]	$2960	$5390	$14700

[1]Same home heating needs assumed as used in Table 1.1. Cogenerator recovers 50% of biogas energy as hot water.
[2]Cogenerator recovers 20% of biogas energy as electricity.
[3]Biogas production rate assumed to be 35000 kJ per cow per day.
[4]Fuel oil is valued at $0.34/liter and electricity at $0.05/kWh.

Presently it is estimated that methane is used in internal combustion engines in over 400,000 vehicles around the world. It has been used in fleet vehicles for over 40 years in Italy, and it is known to power thousands of megawatts of existing cogeneration power (McGeer and Durbin, 1982). Thus, the main unknowns relate to the size of installation, and the use of a fuel that is diluted with carbon dioxide and contains small quantities of water, sulfur compounds, and some nutrients.

I.C. BIOGAS UTILIZATION OPTIONS

The method for utilizing the biogas from a digester on a dairy farm will greatly influence the value and desirability of anaerobic digestion tecnology. The cyclical patterns of energy use and other specific characteristics of a farm's energy needs can cause difficulties in the use of a biogas fuel. For the following analysis, three alternative uses of biogas are considered, including direct heating, liquid fuel replacement for mobile vehicles, and cogeneration of electricity and hot water (see Figure 1.2). These alternatives will be discussed based upon the following criteria: (1) cost of the energy sources replaced by the biogas; (2) portion of the biogas that can either be consumed for replacing farm needs or marketed; (3) capital and operating costs of utilization options; and (4) technical feasibility of options.

I.C.1. Heat Energy Option

The simplest means of utilizing biogas would be to replace fuels used for water, space and other direct heating needs of the farm and home. Current natural gas-fired boilers, furnaces, and water heaters could be adapted to biogas with only minimal modifications. Because different volumetric mixtures of fuel and air are needed to allow proper combustion of biogas and natural gas, some adjustments of airflow rate are necessary. The lower volumetric heat content of biogas will result in a lower heat output of an appliance, which can also be corrected if desired. The most critical concern will be to supply sulfur free biogas to the heating appliances. An iron sponge or other filtering mechanism must be included in the biogas line. No serious technical problems are anticipated with this option.

Biogas will generally replace a mixture of electricity and fuel oil presently used for heating applications on most dairy farms. These fuels are predominantly used on dairies in the Northeast for heating of water, residences, and farm buildings (Bureau of the Census, 1982). Electricity represents the most expensive energy source purchased by the dairy ($21.6 per GJ at $0.07 per kWh), while fuel oil is a far less expensive energy source ($7.80 per GJ at $0.30 per liter). Use of biogas for direct heating will replace a mixture of high and moderately priced fuels on Northeast dairies.

The capital and operating costs of the direct heating option should be reasonably low. The primary capital cost will be associated with gas filtering, delivery of the gas to the point of use, and replacement or modification of water and space heating appliances. The primary operating cost of the system will be associated with the hydrogen sulfide scrubbing mechanism. Jewell et al. (1982) reported that the operating cost of an iron sponge filtering unit was approximately $1.7 per cow per year.

The primary difficulty with the utilization of biogas for heating is the inability of the dairyman to utilize the majority of the biogas produced. Timing of the digester and farm heating needs can be in conflict (see Figure 1.3). The greatest demand for heat for the farm and digester both occur in the winter. On smaller dairies sufficient biogas may not be available for supplying both needs. Most dairies have a dramatically reduced need for heat in the summer at the same time the greatest quantity of biogas would be available for farm use. Koelsch and Walker (1981) reported that a typical 50-, 100-, and 300-cow dairy would use only 37%, 25%, and 20%, respectively, of the gross gas production of a digester. Marketing of the

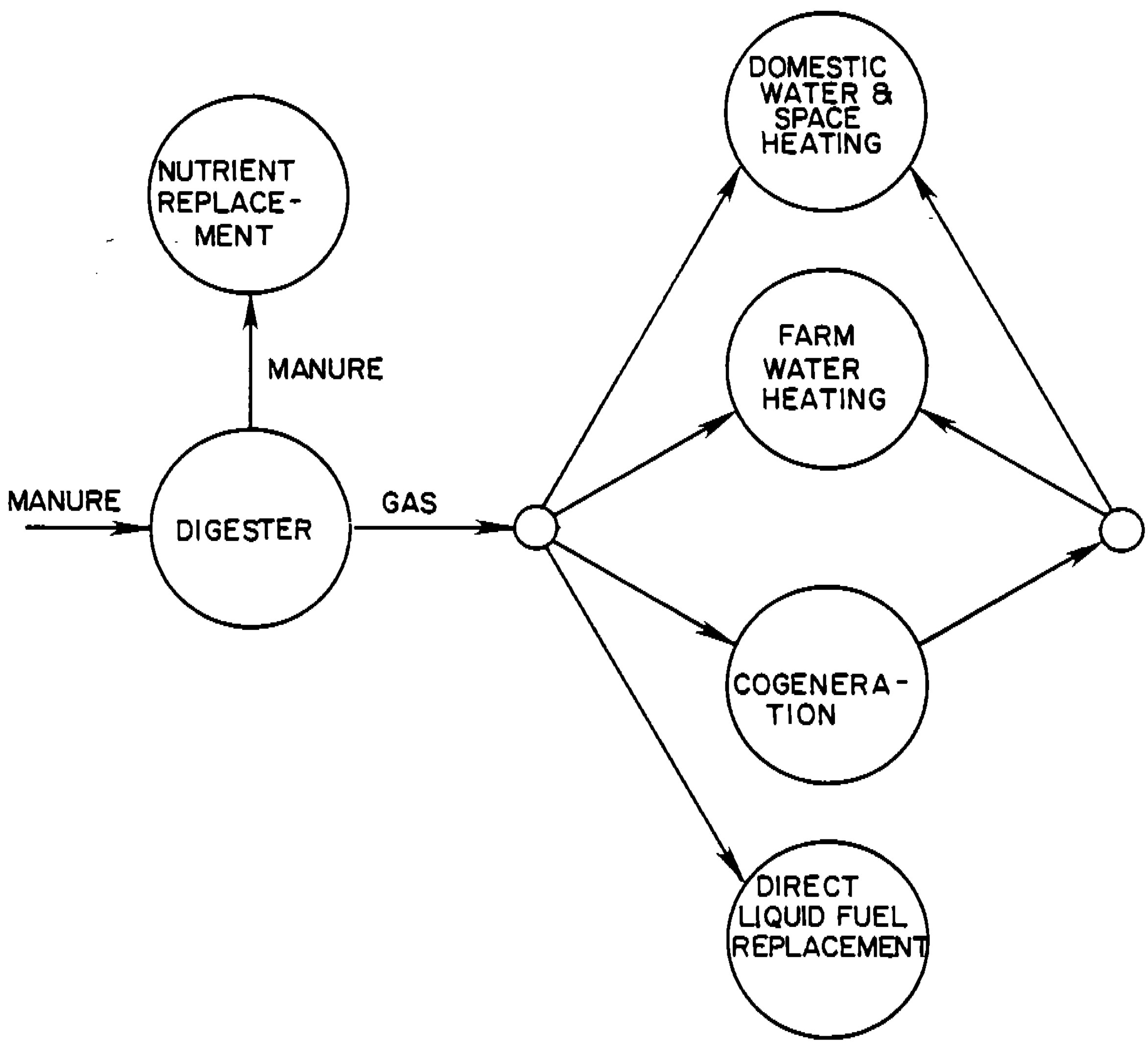


Figure 1.2. Biogas utilisation options.

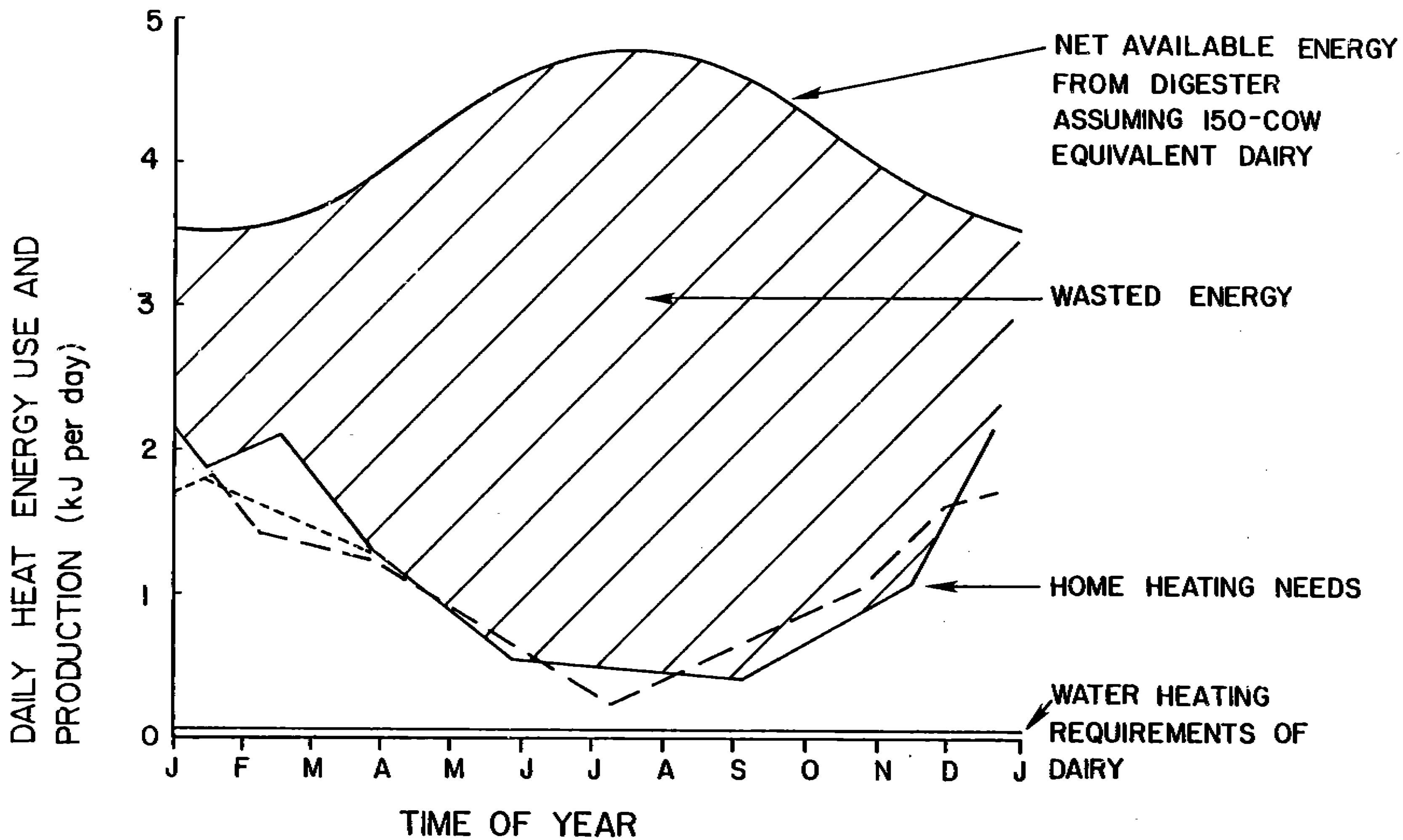


Figure 1.3. Heat energy demands and net energy available from a 150 milking cow equivalent commercial dairy (Walker, 1981).

excess biogas to users off the farm is generally not considered an option because of the cost of a delivery system and the winter timing of the heating needs of most other potential users. Unless profitable spring, summer, and fall uses of the biogas can be found on a dairy, this option will provide a low return.

I.C.2. Mobile Farm Fuel Option

As discussed earlier, methane is an excellent fuel for spark ignition engines while it is a less desirable fuel for compression ignition engines. Few technical problems would be encountered in replacement of gasoline use with biogas in the spark ignition engine. Procedures for converting a gasoline engine to a gaseous fuel are commercially available and have found many applications for compressed natural gas. Replacement of diesel fuel in compression ignition engines offers more potential problems and greater conversion costs. Since gasoline is still the predominant fuel used on dairies in the Northeast, this option offers considerable potential (Bureau of the Census, 1982).

The primary technical problem with the application of biogas to an engine involves the storage of the gas. Gasoline has an energy density of 33 GJ/m^3 at atmospheric pressure. Compressing biogas to the same pressures used in mobile compressed natural gas applications (16,600 kPa) will only produce an energy density of 3.3 GJ/m^3, or 10% of the energy density of gasoline. Removal of the carbon dioxide from the biogas will increase the energy density to 5.5 GJ/m^3. However, commercial equipment for removal of carbon dioxide is generally not commercially available in sizes appropriate for most dairy farms (Walker, 1981). The use of biogas for mobile applications may be limited to vehicles used for short duration or short-range tasks.

The use of biogas as a replacement for gasoline in an engine will result in some loss of power. Assuming operation at stoichiometric conditions for biogas containing 60% methane, one should expect a 15% to 20% loss of maximum power output as compared to operation on gasoline. For many applications this loss of power may not be considered serious, and it can be corrected by use of a turbocharger.

This option replaces a moderately priced fuel on the farm. Gasoline at 29 to 33 cents per liter ($9.70 to $11.00 per GJ) is less expensive than electricity but generally more expensive than diesel fuel and fuel oil. Liquid fuel use on the dairy is highly seasonal in nature. Peak fuel consumption occurs during spring planting and during hay and corn harvesting (Walker, 1981, and Williams et al., 1975). These peaks generally occur for short periods of time between April and October. The gasoline use patterns more closely matches the available energy from a digester with the summer peaking use and the diminishing winter need than did the heating option.

The capital and operating costs of this use appear to be a major objection. Loll and Dohne (1982) concluded that "biogas-driven tractors and vehicles are not expected to meet with a ready market in the industrialized countries since they do not reach profitability." The evaluation of a specific commercial dairy farm suggested that application of biogas to specific vehicles used daily for short duration tasks would be either marginally economic at best and could be economically unrealistic depending upon the value associated with the biogas. Walker (1981) states that $3,000 per year worth of gasoline could be displaced by an investment of $12,750 and an annual operating cost of $1,700 to $2,000 on one specific dairy.

I.C.3. Cogeneration

The technology currently exists for utilizing biogas for the generation of electricity and hot water. Gas-fueled spark ignition engines are commonly available commercially. Small scale electrical generation equipment is readily available for both independent and parallel power generation with the utility. Cogeneration units are not readily available in sizes less than 15 kW, which would be appropriately sized for a 150-cow dairy. Smaller dairies may find this technology inappropriate without the costly investment in biogas storage facilities to allow operation for less than 24 hours per day.

The electrical energy demand of the dairy farm is relatively constant throughout the year (Petersen et al., 1980, and Walker, 1981). However, it does vary dramatically over a 24-hour period, with the peaks occurring during milking and feeding operations (Koelsch and Walker, 1981). As discussed earlier, electricity is generally the highest priced fuel that a farmer purchases. Electricity is also a marketable fuel at a reasonably attractive price in some states due to current federal and state regulations. Thus, electricity represents a high value potential product that can be easily used on the dairy or marketed to the electric utility.

The heat energy produced by cogeneration suffers from some of the same problems discussed earlier under the heat energy option. This heat energy could be used to replace a mixture of high- and medium-priced fuels. However, timing of the farm and digester heat needs conflict with both peaking in the winter and little need for heat in the summer (see Table 1.2). In addition, transportation of a low quality energy such as hot water is expensive. Use of the hot water may be limited to within 100 meters of the point of production. Thus, electricity may be the primary product of value from a cogeneration system (see Table 1.3). The financial return from cogeneration is considerably greater than that of the heating option.

The primary concern with this option is the capital and operating cost of a cogeneration system for biogas. A 25 kW engine-generator set with engine coolant and exhaust heat recovery designed to use biogas may cost in excess of $25,000. This unit would be properly sized for about a 250-cow dairy. Several thousand additional dollars would be spent for electrical and hot water connections to the dairy and a gas filtering system. In addition, the operating cost of this unit may amount to about $2,200 per year (Koelsch and Walker, 1981).

TABLE 1.2. HEATING OPTION: EQUIVALENT FUEL OIL REPLACEMENT OF HEATING NEEDS OF TYPICAL DAIRIES (Koelsch and Walker, 1981)

	Number of Cows					
	50		100		300	
Month	Liters Replaced	% of Total Farm Needs	Liters Replaced	% of Total Farm Needs	Liters Replaced	% of Total Farm Needs
Jan.	810	73	1230	100	2700	100
Feb.	770	76	1140	100	2520	100
Mar.	620	95	1020	100	2290	100
Apr.	650	100	770	100	1790	100
May	460	100	580	100	1410	100
June	310	100	430	100	1110	100
July	260	100	390	100	1020	100
Aug.	270	100	400	100	1040	100
Sept.	360	100	490	100	1230	100
Oct.	550	100	680	100	1600	100
Nov.	740	100	860	100	4970	100
Dec.	890	89	1090	100	2510	100
Total	6690	88	9100	100	21200	100
% of Total Biogas Used	37%		25%		20%	
$ Value at 0.30 per liter	$2,000		$2,700		$6,400	

TABLE 1.3. ANNUAL FARM ELECTRICAL PRODUCTION BY COGENERATOR AND ITS VALUE (Koelsch & Walker, 1981).

	Number of Cows		
	50	100	300
Electrical production (kWh)	37,400	74,900	224,600
Fuel oil replacement by hot water (liters)	3,600	6,800	19,800
% of farm heat needs replaced	52%	81%	98%
$ value[a]	$3,700	$7,300	$21,700

[a]Assumes electricity value of $0.07 per kWh and fuel oil value of $0.30 per liter.

With the currently available information, it would appear that both direct heating and cogeneration provide the most immediate potential for utilizing biogas. The use of biogas in boilers, water heaters and furnaces may be the most desirable alternative for smaller dairies. For dairies of at least 100 cows or more, the use of biogas for cogeneration would appear to be the more desirable option.

I.D. BIOGAS UTILIZATION AS AN ENGINE FUEL

The use of gaseous fuels in internal combustion engines has been a common practice in the past. Engine manufacturers have developed rather detailed specifications for use of methane-based fuels such as sewage treatment plant gases, landfill gases, and natural gas in engines (Riback, 1982; Onan, 1977; Caterpillar, 1972; Caterpillar, no date). Many of the recommendations for sizing of engines, carburetion systems, and installation of engines provide valuable information for use of biogas fuel in an engine.

The gaseous fuel produced by an anaerobic digestion process consists primarily of methane and carbon dioxide. Various investigations have reported that the methane composition of biogas ranges from 50% to 80% by volume, with the remaining volume being primarily carbon dioxide. Biogas produced from an anaerobic digester utilizing dairy manure as a feedstock will generally produce biogas containing 58 to 61% methane (Jewell _et al._, 1981). The characteristics of biogas and other fuels are described in Table 1.4.

The high octane rating of methane is a good indication that it is a suitable fuel for high compression spark ignition engines due to the fuel's tendency not to pre-ignite in the cylinder (Obert, 1973). Neyeloff and Gunkel (1975) reported that a compression ratio between 11 and 16 to 1 was desirable for a methane fueled CFR engine. They also noted that peak fuel economy could be obtained at slightly lean fuel-air mixtures. The value of lean fuel operation was further confirmed by Stahl _et al._ (1982b) on a biogas-fueled engine operating at 1200 rpm. They also reported that operation of this engine required spark settings in excess of 40 degrees before top dead center (BTDC).

Biogas has also been considered for use in dual-fueled compression ignition engines. Some diesel fuel must be injected to initiate combustion in the cylinder. Problems have been reported with the sizeable requirements for diesel fuel, difficulties in timing of diesel injection, and rough combustion within the cylinder (Persson and Bartlett, 1980; Kofoed, 1981). However, this option does offer the opportunity for higher energy efficiency.

I.D.1. State of the Art of Small-Scale Cogeneration

The conversion of rotating shaft power on an engine to electrical energy on farms has generally been accomplished with synchronous generators. However, the equipment requirements, costs, and potential liability problems with paralleling a synchronous generator

TABLE 1.4. CHARACTERISTICS OF BIOGAS AND MORE CONVENTIONAL FUELS[a]

Fuel	Higher Heat Value kJ/kg	Higher Heat Value kJ/m^3 [b]	Lower Heat Value kJ/kg	Lower Heat Value kJ/m^3	Stoichiometric Air-Fuel Ratio	Flammability Limits Low	Flammability Limits High	Octane (Research + Motor)/2
Methane[b]	55,568	37,100	50,050	33,400	17.21	5	15	120
Carbon Dioxide[b]	0	0	0	0	--	--	--	--
Hydrogen Sulfide	17,400	24,700	16,100	22,800	6.12	4.30	45.50	—
Biogas[b,c]	25,200	22,300	22,600	20,000	6.08	—	—	--
Octane[d]	47,894	--	44,426	--	15.1	0.84	3.20	- 18.5
Propane	49,971	93,800	45,970	86,340	15.7	2.37	9.50	104.5

[a]Information compiled from Baumeister, 1967; Caterpillar, 1972; and Obert, 1973.

[b]At 20°C and 1 atmosphere

[c]Based on 60% methane and 40% carbon dioxide

[d]Octane is a major component of gasoline. Gasoline has an approximate octane rating of 90.

with the electric utility grid tend to discourage this option for smaller installations (Caterpillar, 1978; Patton and Iqbal, 1981). Thus, if conventional generating equipment is to be used, it will probably be operated independent of the utility grid. Current New York State law encourages the connection of a biogas-fueled cogenerator to the utility due to the minimum value of electricity sold to the utility by a small power producer being set at $0.06 per kilowatt-hour (Howansky, 1981). Similar laws in other states also promote the connection of small power producers to the utility.

Induction generators offer the ability for a small power producer to operate on the utility grid with minimal problems (Chancellor, 1979; Barkle and Ferguson, 1954). The need for relatively simple controls and protective devices and no synchronizing equipment for parallel operation favors the induction generator (Patton and Iqbal, 1981). Other characteristics of induction generators such as potentially lower initial cost, low maintenance cost, and inability to contribute sustained current to a short circuit also offer additional reasons for their consideration (Nailen, 1980).

In addition to electrical production, an engine generator set can be used for producing hot water from the engine's waste heat. Caterpillar (1978) reports that the engine coolant heat and exhaust heat represent the largest heat resources (Table 1.5). Stahl et al. (1982a) noted that between 50 and 60% of the fuel's energy could be recovered by heat exchangers on the engine coolant and exhaust system. This energy can be used for digester heating as well as space and water heating needs of the farm.

TABLE 1.5. ENERGY PRODUCTION BY A 50 KW GENERATOR (Caterpillar, 1979)

	Total Energy	% of Total
Electrical Energy	52 kW	29%
Heat Energy		
Heat Rejection to Coolant	47.5 kW	27%
Heat Rejection Radiation from Engine	14.0 kW	8%
Heat Rejection Radiation from Generator	6.3 kW	4%
Heat Rejection to Exhaust Gas	57.1 kW	32%

The maintenance and depreciation costs of engines that burn biogas are currently unknown factors. Such factors as the rate of depreciation of the engine, time interval between major and minor overhauls, and oil change intervals can be major costs that dramatically influence the economics of generating electricity with biogas (Koelsch and Walker, 1981). Efforts to predict engine life for operation on methane-based fuels have been reported. Fox et al.

(1981) suggested that a spark ignition engine operating on pure methane and a methane/carbon dioxide mixture will have a life of approximately 5000 hours and 6000 hours, respectively. They also suggested that high brake mean effective pressure engines (BMEP) and engine operation at lean fuel-air mixtures will result in longer engine life. Picken and Hassaan (1983) suggested that an engine life ranging from 5200 to 13200 hours might be expected from a 19 kW engine operating in a particular application. Koelsch and Walker (1981) have suggested that the general trend for favorable cogeneration specifications would include: (1) use of generation units with engines operating at 1200 rpms or less; (2) use of heavy duty engines; (3) inclusion of long-life bearings, brushless contacts, and high quality insulation in generator construction; (4) use in continuous rather than intermittent operation; and (5) attentive operator care and minimum contaminants such as sulfur in the feed gas.

In the mid-1970's the Fiat Motor Company developed a small cogeneration system for distribution in Europe (Totem, 1978). This 15 kilowatt capacity unit utilized a 903 cm^3 Fiat engine (127A). This unit operated at a high rpm (3700 rpms) and had been modified for biogas utilization by changing the compression ratio and increasing the oil reserve capacity. The manufacturer claims that the total energy efficiency exceeds 90%, with 26% recovery of the biogas energy in electricity and about 65% recovery of heat from the engine cooling system.

The first cogeneration facility installed on a dairy occurred in Ludington, Michigan, in 1973, while the most well-known application occurred at the Mason-Dixon dairy farm in Pennsylvania in 1979. There are very few small units that have accumulated a significant amount of operating time with a biogas fuel.

Coppinger et al. (1978) emphasize the importance of operating the cogenerator under proper loading conditions. In a 500-cow dairy unit, an underloaded cogenerator operated at less than 10 percent energy conversion efficiency, or less than 40 percent of its expected efficiency.

I.D.2. Sulfur in Biogas

The interaction between hydrogen sulfide in biogas and engine life appears to be poorly understood. Previous experience with engines operating on biogas from municipal waste treatment digesters and landfill disposal sites is of little value due to the magnitude of difference in hydrogen sulfide levels. Gas from a digester of a sewage treatment process will typically contain 100 parts per million (ppm) of hydrogen sulfide (Stine and Bready, 1976). The hydrogen sulfide level of landfill gas typically is less than 20 ppm and, total sulfur compounds will be less than 40 ppm (Blanchet, 1977). Biogas from dairy manure digesters will often exceed 1000 ppm.

There are two conventional methods of limiting sulfur contaminants in the biogas. Selection of oil and monitoring of oil condition is recommended as one alternative (Waukesha, 1981). Waukesha

(1981) recommends that "engines ... with gaseous fuel containing over 0.1% hydrogen sulfide or liquid fuel containing over 0.5% sulfur should use oil compounded to a total base number (TBN) of 8 or higher, so that the oil can adequately counter the acids formed in the combustion of such fuels." The TBN rating of a fuel is an indication of "the degree of alkalinity, or amount of acid the oil can neutralize...." (Engine Manufacturers Association, 1982). Recommendations by Cummins Engine (1980) and Detroit Diesel (1983) suggested a minimum TBN rating of 2.0 and 1.0, respectively, for used oil; while Waukasha suggested a minimum TBN level of 4 for used oil. However, work by Cartwright and Carey (1980) indicates that TBN may not be the only factor to consider for the purpose of acid neutralization for preventing potential corrosion problems. They contend that "not all highly overbased detergents will neutralize organic oxidation acids; criteria other than simply TBN need to be considered when choosing detergent for the control of used oil acidity."

Treatment or filtering of the hydrogen sulfide offers a second alternative for control of corrosive problems. Jones and Perry (1976) reported that several processes exist for removal of hydrogen sulfide and/or carbon dioxide from natural gas, including the iron sponge process, monoethanol/diethanol amine process, and molecular sieve process among others. He also suggests that the iron sponge process is economically viable with gas streams with less than 340 ppm. Norstrand (1953) and Bacher (no date) reports that the form of sulfur rather than the quantity of sulfur should be the primary concern. Removal of dissolved sulfur compounds should reduce corrosive problems within an engine. The Winslow sour gas conditioning element is designed to "neutralize the dissolved sulfur compounds (mercaptans)" in digester and natural gas streams and reduce corrosion problems.

I.D.3. Economics of Small Scale Cogeneration

An actual 340-cow dairy operation in California with a 40 kW cogenerator was found to be economically attractive but highly sensitive to alternative construction techniques (Chandler et al., 1982). Estimated generator set operations and depreciation costs for 40 to 65 kW units were reported to vary between $0.009 to $0.015 per kWh of generation capacity for intermittent and continuous operation.

Quok et al. (1984) reviewed the potential market for agricultural waste digestion and cogeneration in California. They found several hundred facilities of a size that would have between a 20 and 25 percent return on investment.

Anderson (1982) concluded in an economic assessment of a 100-head dairy cogeneration example that it was not cost-effective at this size. Breakeven energy costs were estimated to be $7.69/GJ for natural gas, $0.078/kWh (off peak) and $0.115/kWh (peak).

Koelsch and Walker (1981) estimated that the annual operating and depreciation costs of cogeneration sets with capacities of 20 to 25 kW varied from $0.018 to $0.034 per kWh. They acknowledged that these values included unsubstantiated assumptions such as optimistic total engine lifetime of 100,000 hours, and periods between major overhauls of 20,000 hours.

The application of cogeneration to farms is especially difficult because of the sensitivity of economics of scale. Figure 1.4 shows the general cost trends for varying sizes of cogeneration units. Most commonly available cogeneration units have capacities in excess of 100 kW. Wastes from 1000 cows are required to operate a 100 kW cogeneration unit continuously. The relationship of digester costs to cogeneration costs are summarized in Figure 1.5. These values emphasize that at most scales, farm scale cogeneration costs nearly equal biogas production costs.

In summary, cogeneration is an important technology already commercial at large scale. Application to farms where biomass quantities are limited results in biogas quantities sufficient to operate cogenerators with capacities of less than 100 kW. Operational data on these smaller farms are scarce. Cornell University's full scale biogas demonstration project was used to document the feasibility of using cogeneration on small dairies. It was also the purpose of this project to continue monitoring the two full scale digesters' performance and reliability in their fifth and sixth year of operation.

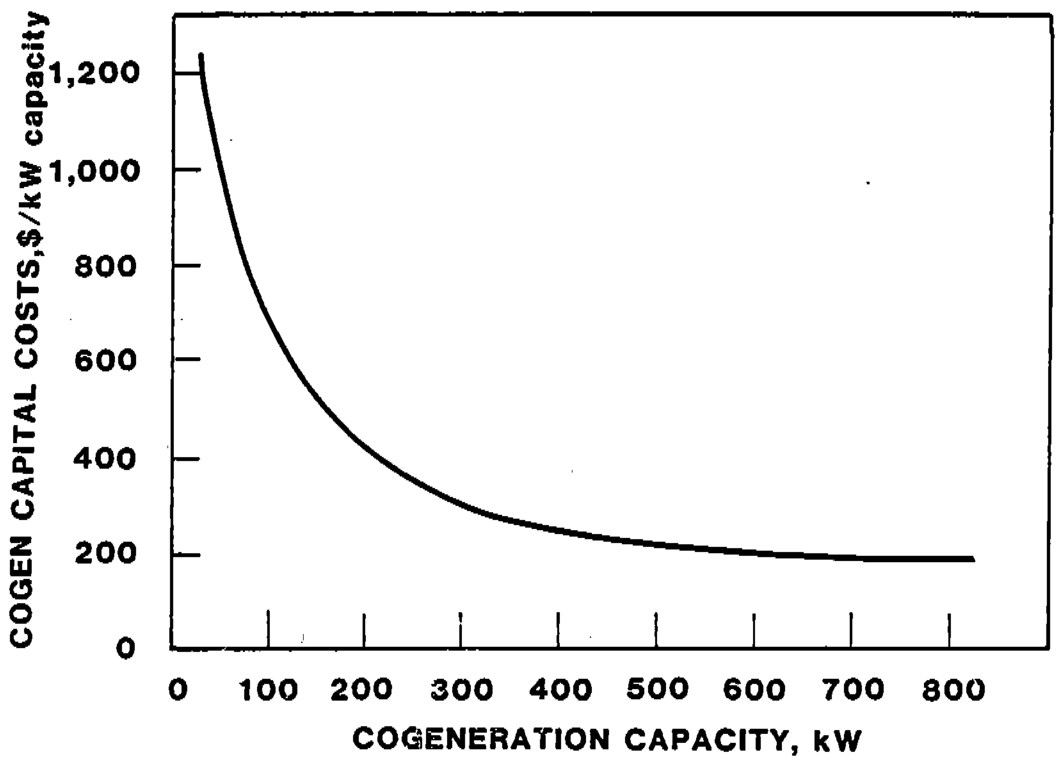


Figure 1.4. General relationship of cogeneration facility size to capital costs.

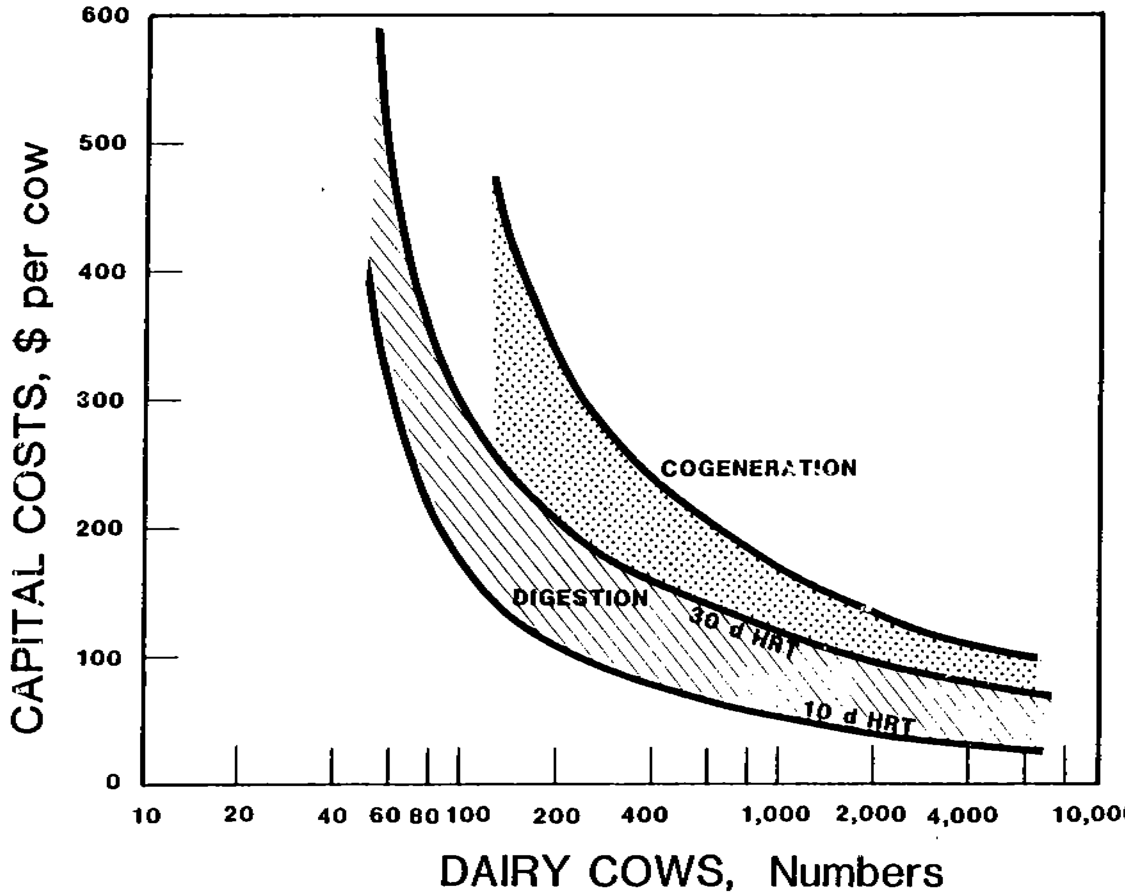


Figure 1.5. Influence of dairy farm size on capital costs of anaerobic digesters (at two different hydraulic retention times) and cogeneration units.

CHAPTER II

MATERIALS AND METHODS

II.A. BIOGAS GENERATION

This study was conducted at the Cornell University Animal Science Teaching and Research Center in Harford, New York. This facility, located 16 miles southeast of campus on Route 38, is an ultramodern complex for full scale teaching and research with large animals, and includes beef, dairy, and sheep complexes. The dairy complex illustrated in schematic form in Figure 2.1 was managed and operated by the Animal Science Department of Cornell University and consisted of five interconnected barns housing over 600 dairy animals, including 320 milking cows. The dairy manure feedstock for the full scale experiments was obtained from the second barn, a free stall unit where no bedding was used throughout the majority of the study. The third barn contained the milking parlor and a large research laboratory staffed and operated by the Agricultural Engineering Department. The Animal Science Department in cooperation with the Agricultural Engineering Department provided strong support for the study and made the commitment to insure reliable residue handling, delivery, and final utilization after treatment.

Two full scale anaerobic digesters were constructed at this site to document the possibilities of designing and operating low cost digesters to convert the organic matter contained in dairy manure to biogas. These facilities have been described extensively elsewhere (Jewell et al. 1978, 1980, 1981). The control reactor was a full scale completely mixed reactor design, similar to what might be found at a sewage treatment plant; and the second was a full scale low cost plug flow digester designed by a research team at Cornell University. These two units were operated in parallel for detailed experimental comparison for over five years. Major variables tested included temperature (25° to 35°C), hydraulic retention time (8- to 50-day HRT), and management methods (mixing, pressure, etc.).

In 1979, a large study on the conversion of crop residues funded by USDOE's Solar Energy Research Institute focused on a "dry fermentation" process. A prototype 110 m^3 volume reactor was placed into operation in late October 1981 with wheat straw as the substrate (Jewell et al. 1982). The design of each reactor is summarized in this section of the report.

II.A.1. Manure Transfer

As shown in the manure transfer schematic (Figure 2.1), the manure feedstock was conveyed to the west end of barn 2, using automatically operated floor scrapers. A cross conveyor moved the material to a hollow piston pump manufactured by Hedlund Manufacturing Company. This pump forced the manure twice per day through a 31 cm. diameter PVC pipe, 24.4 m to a feedstock storage tank (T-1). This tank had a capacity of 75.6 cubic meters and stored the manure which was used as the common feedstock for both full scale reactors.

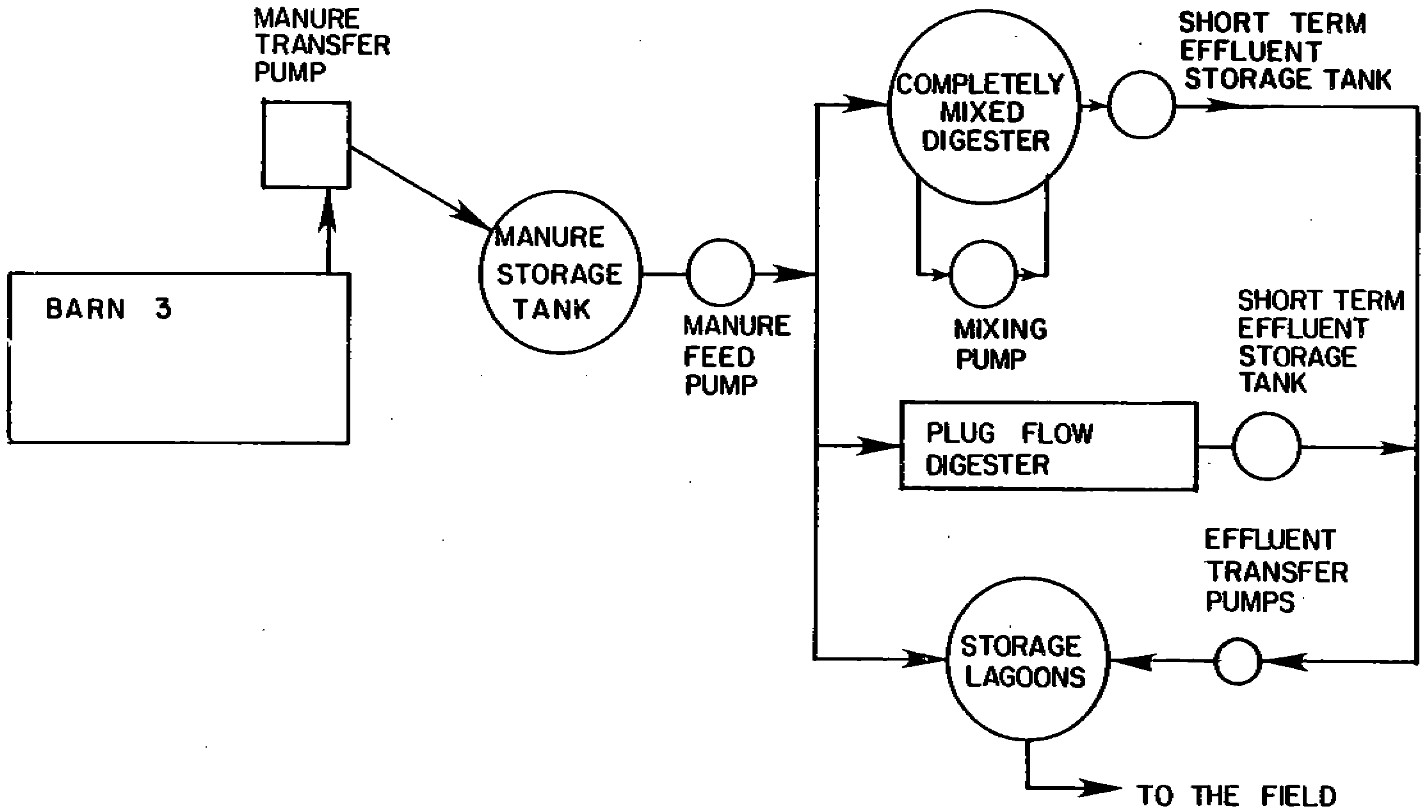


Figure 2.1. A schematic of the dairy manure transfer system.

Both digesters were semicontinuously charged with undiluted dairy manure from the feed storage tank (T-1) five times per week using a Moyno progressive cavity pump with a 7.5 kW electric motor. This pump delivered a relatively constant flow rate of approximately 350 liters per minute, which facilitated accurate loading rates into each digester.

Each reactor was designed with a gravity effluent into a short-term effluent storage tank. These effluent storage tanks were constructed of steel, insulated with 5 cm of polyurethane foam, and had a diameter and height of 2.44 m. These short-term storage tanks were necessary for sampling and also for measurement of the mass flow of manure through each system. They were emptied three times per week using an ITT Marlow 1.1 kW diaphragm pump (for the effluent from the completely mixed unit) or a vertical mount 2.1 kW centrifugal pump (for the plug flow digester effluent). The digested manure was transferred to either a 567 m^3 storage tank (T-3) or an earthen lagoon (53 x 30 x 5 m) for long-term storage. The digested manure was ultimately spread on the farm land as a crop nutrient source by means of liquid handling tank spreaders. A plan view of the manure transfer system is presented in Figure 2.2.

II.A.2. Dry Fermentation System

An existing concrete manure storage tank (6.1 m diameter and 4.9 m deep) was retrofitted to provide the volume necessary for an intermediate scale dry fermentation reactor. Layers of baled wheat straw were placed in the tank between layers of anaerobically digested dairy manure until the reactor was completely filled (110 m^3). A 0.91 mm hypalon liner with a 10 x 10, 1000 denier polyester scrim (purchased from Staff Industries) was used as the biogas collection cover of the reactor. It was anchored to the top perimeter of the reactor and was held in an inflated state by the biogas produced by the system at pressures between 1 and 5 cm of water column. Biogas was vented from the system through a 7.6 cm diameter steel pipe.

The reactor temperature was maintained at 35°C using an internal hot water heat exchanger. The reactor walls were insulated with 7.6 cm of spray urethane foam sealed with a sprayed layer of butyl rubber paint which provided complete moisture and gas impermeability. The reactor floor was insulated with 10 cm of rigid Foamglas insulation and the reactor cover was insulated with 15 cm of rolled fiberglass insulation.

The reactor was designed to operate in a batch mode at a total solids concentration of approximately 25 percent on a wet basis. A schematic of the system is presented in Figure 2.3.

II.A.3. Completely Mixed Control Digester

The completely mixed control digester had been in operation since April 27, 1978, when the project was initiated. It consisted of a concrete stave silo tank which was retrofitted to serve as the control reactor for comparison to the Cornell design plug flow digester. The mixed reactor, shown in Figure 2.4, was operated a total of

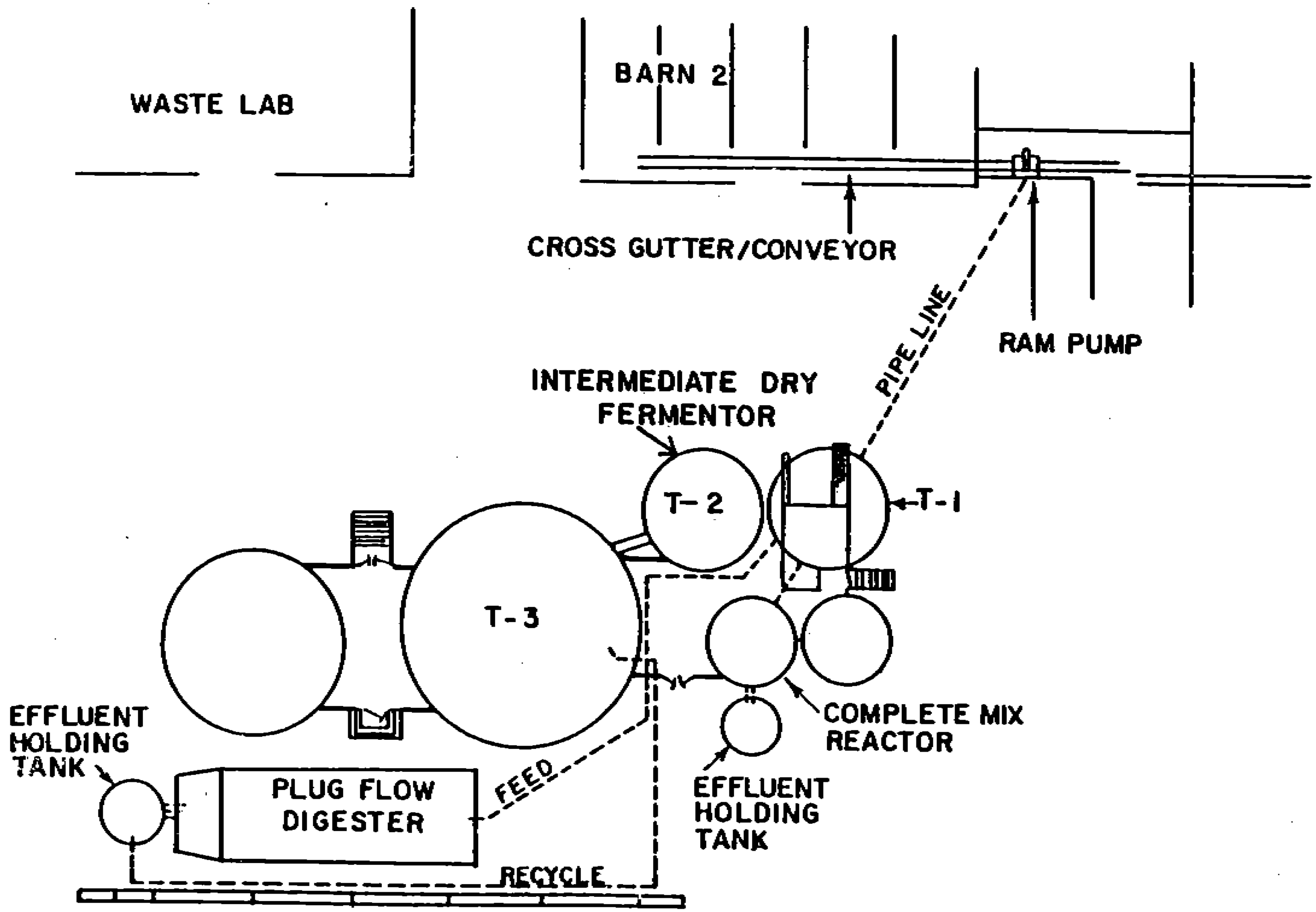
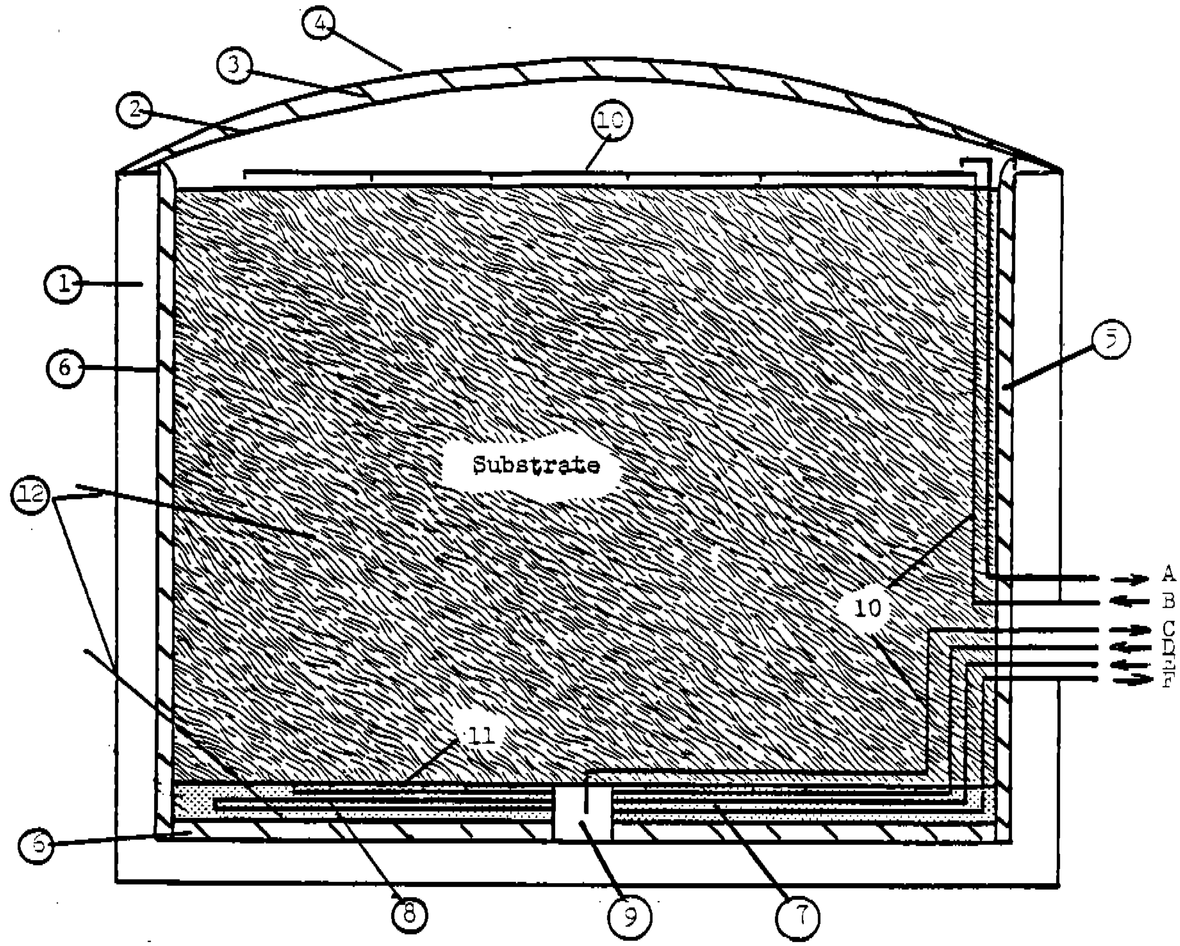


Figure 2.2. Physical layout of the full scale anaerobic digester site.



Item	Description
1	20' Diameter x 16' Deep Concrete Tank
2	36 mil Hypalon Cover
3	6" Fiberglass Insulation
4	6 mil Polyethelene Plastic (2 layers)
5	4" Flexible Gas Takeoff
6	3" Urethane Sprayed Insulation
7	4 1/2" Foamglas Insulation
8	Gravel Drainage Bed
9	2" Black Steel Heat Grid
10	Leachate Recycle Piping
11	Leachate Recycle Distribution Grid
12	Aeration Grid
13	Control Probe Wells
A	Leachate Recycle Pump Discharge
B	Leachate Recycle Pump Suction
C	Aeration Grid Input
D	Heat Grid Supply
E	Heat Grid Return
F	Biogas Takeoff to Storage

Figure 2.3. Schematic diagram of the 110 m^3 reactor used to scale-up the dry fermentation concept.

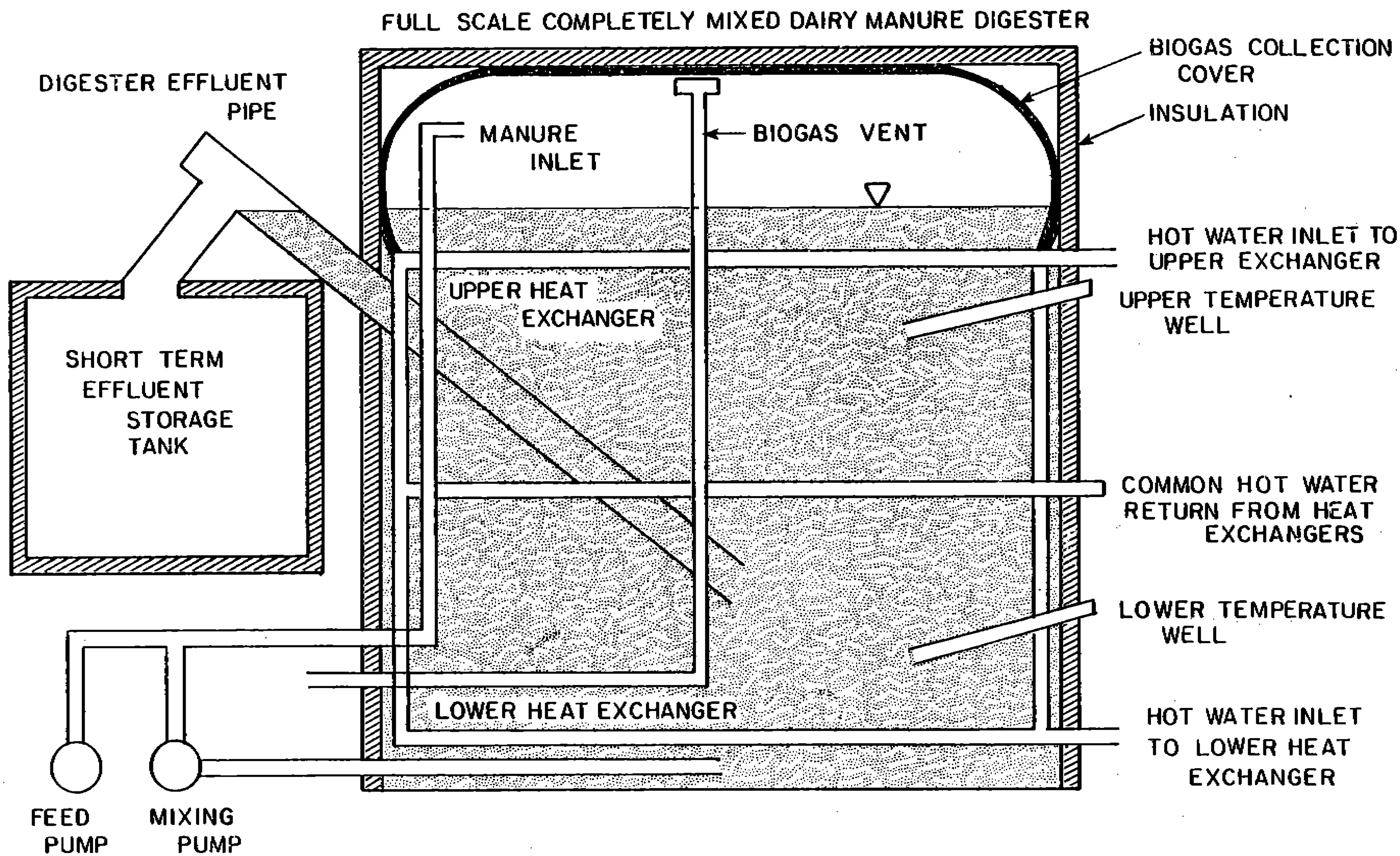


Figure 2.4. Cross section of the full scale completely mixed control digester.

1875 days until June 14, 1983. It was cylindrical in shape with an inner diameter of 4.27 m and a total volume of 52.4 m^3. The effective manure depth was 2.8 m, and the effective reactor volume was 35.4 m^3 throughout the study.

The feedstock manure was pumped into the reactor using a Moyno progressive cavity pump through a 10 cm diameter feed pipe located in the side wall of the reactor. The contents of the reactor were completely mixed for 15 minutes every three hours using a Vaughn centrifugal chopper pump; thus, mixing was accomplished by the fill and draw method. The effluent from the digester flowed by gravity through a 15 cm diameter pipe into one of the short-term storage tanks.

Two internal hot water heat exchangers consisting of octagonal loops of black steel pipe, 5 cm in diameter and 13.7 m in length were located 1.9 and 0.3 m from the digester floor passed through the reactor side wall below the liquid level and into a control room where they were attached to a hot water source to supply heat to maintain the digester at approximately 35°C.

Three sources of hot water were used during the study, including a dual fuel boiler manufactured by Fulton Boiler Works capable of operating using biogas or propane, an instantaneous hot water boiler manufactured by Poloma Pak which also could be operated using either biogas or propane, and the recovered heat from the operation of the cogenerator. Two temperature wells in the reactor side walls contained sensors to control the flow of hot water in each grid and thus control the reactor temperature.

Biogas was collected using a flexible hypalon material manufactured by Cooley Inc. This material was 45 mils thick, 10 x 10 weave density, and contained 1000 denier heat set polyester scrim. The perimeter of the hypalon material was anchored to the upper heat grid, which was solidly anchored to the reactor side walls 15 cm below the manure surface, thus providing a liquid gastight seal. Biogas was vented from the reactor through a 7.6 cm diameter pipe which was mounted vertically within the reactor and had a horizontal extension which passed through the reactor side wall below the liquid surface. Once outside the reactor the condensation was removed from the biogas in a condensation trap.

The exterior of the reactor was insulated with 9 cm of polyurethane foam. Five centimeters of this type insulation were also sprayed onto the exterior of both short term effluent storage tanks.

II.A.4. Cornell University Plug Flow Digester

The full scale plug flow digester designed by Cornell University (Figure 2.5) consisted of a soil-supported trench lined with a flexible hypalon material and covered with a flexible material capable of trapping the biogas. It was operated for 1839 days from June 2, 1978 to June 14, 1983. During this study two reactor designs were tested, the first from start-up in June 1978 until June of 1982, and the

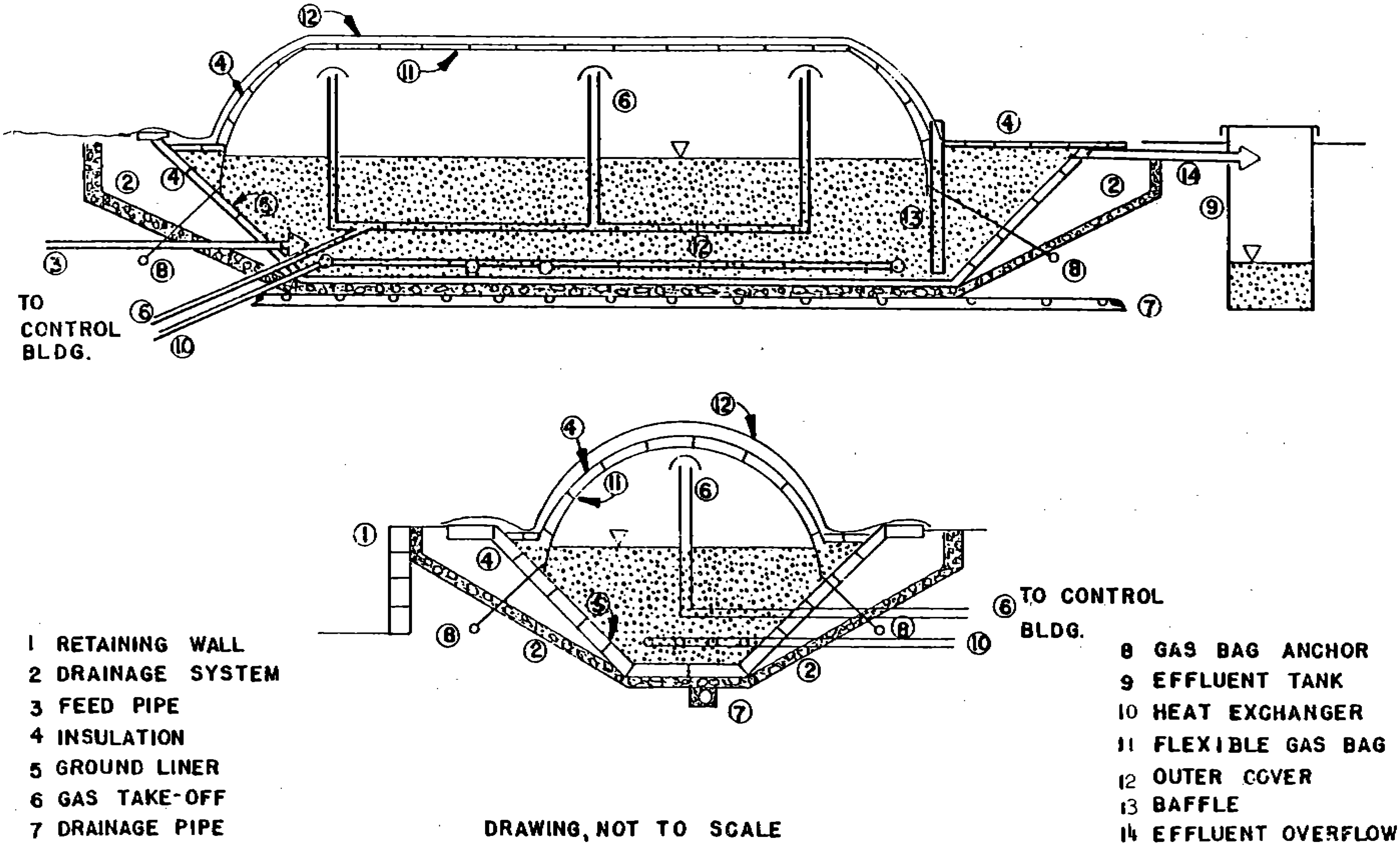


Figure 2.5. Schematic of the components within the full scale plug flow digester.

second from that point until the end of the study. Only the second will be described in detail in this report; however, a complete description of the first system is presented in Jewell et al. (1981).

The original design was a soil-supported trench having an overall length of 17 m, a width of 4.75 m, and a depth of 1.83 m. The effective depth of manure in the reactor was 1.37 m, which resulted in an effective reactor volume of 40 m^3. Gravel formed the sidewalls (slope = 1.1) and floor of the reactor and was also important as the means of rapidly draining any surface water from the reactor site. In both designs it was essential that all moisture be removed from the immediate reactor area to minimize the thermal conductivity of the soil and thereby minimize the heat loss from the reactor. All moisture drained to a 46 cm diameter weeper pipe located 0.6 meters beneath the reactor floor.

The trench of both designs was lined with ethylene propylene denier monomer (EPDM), a basin liner material purchased from Burke Rubber Company. This material had a 30 mil thickness and was reinforced with an 8 x 8 weave density of 250 denier nylon. A large 7 x 20 m sheet of EPDM was positioned over 10 cm of Foamglas insulation which also lined the trench interior.

II.A.4.a. Original Cornell Design

The biogas collection system used in the first design consisted of a flexible sheet of estane polyurethane anchored using a dead weight system around the top perimeter of the digester 15 cm below the manure surface level. The estane material had a 2000 denier polyester scrim, 10 x 10 weave density, and a 45 mil thickness. The 6 x 18 m sheet, purchased from Cooley Inc., was rated to be slightly sensitive to ultraviolet radiation (sunlight) degradation, but temperature-resistant and flexible at temperatures from -51°C to 50°C. The perimeter of the flexible estane cover was anchored to a dead weight system slightly below the manure surface level with removable clamps for easy access to the digester interior and to provide a liquid seal to collect the biogas. Biogas was vented from the cover, which was held in an inflated state at a pressure of 1 to 2 cm of water column, through steel pipes mounted vertically in the digester. These pipes had a horizontal extension below the manure surface level which passed through the reactor side wall at a slight downward slope to a control room where the biogas became available for use.

The desired reactor operating temperature of 35°C was maintained with a closed loop hot water recirculation system consisting of two heat exchangers located 30 cm above the reactor floor. Each heat exchanger consisted of four 10 cm diameter steel pipes connected side by side in series with an inlet and outlet extension which passed through the reactor side wall below the manure surface level. One exchanger 3 m in length was positioned in the front part of the digester and served to heat the incoming manure while the second, 12 m long, occupied the rear portion of the reactor and maintained the rear portion of the digester at the desired temperature. Two temperature wells located over each exchanger contained sensors which controlled the flow of hot water to each exchanger to maintain the appropriate digester temperature.

The full scale plug flow digester required insulation to minimize heat loss in three areas of the digester: the soil to slurry boundary, the slurry to air boundary, and the flexible cover to air boundary. As mentioned earlier, ten cm of Foamglas, a rigid structure insulation of cellular glass manufactured by Pittsburgh Corning, was used to line the slurry to soil boundary between the EPDM basin liner and the soil. Digesting manure exposed to the air around the outside perimeter of the digester was insulated with 5 cm polystyrene boards; and 15 cm of rolled fiberglass insulation, protected from the weather with a 140 m^2 sheet of polyethylene, was placed over the inflated biogas cover to minimize the significant heat loss potential from this area.

The feedstock manure entered the digester through a 10 cm steel pipe located in the front end of the digester 0.61 m above the reactor floor. The manure was pumped to the digester three to five times per week using the Moyno pump and flowed by gravity along the length of the digester under a plywood baffle and into the short-term storage tank.

II.A.4.b. Cornell's Modified Plug Flow Digester

Problems with the biogas collection system of the original plug flow design necessitated remodeling of the reactor. Construction began June 2, 1982 and was completed July 7, 1982. The new design, shown in Figure 2.6, upgraded the original with a new flexible cover material, cover anchoring, and manure effluent systems, and also increased the reactor volume from 40 m^3 to 93.5 m^3.

The estane cover material was removed from the original reactor design along with the dead weight anchoring system, effluent baffle, and biogas vent pipes. A steel reinforced concrete collar with a cross-sectional area of 0.014 m^2 was poured around the top perimeter of the reactor such that the new reactor width became 4.6 m and the length 16.2 m. This concrete collar became the means to anchor the new biogas collection cover.

The new cover material chosen was a 6.1 m x 18.3 m sheet of XR-5 8130 chemical and oil resistant polymer coated polyester-based fabric manufactured by Shelter-Rite and purchased from National Seal Company. It had a 10 x 10 weave density, a 30 mil thickness, and was reported to be chemical, microorganism, and ultraviolet light resistant.

After the biogas collection cover was in place and inflated with biogas, fiberglass rolled insulation having a thickness of 15 cm was positioned over the top. A polyethylene sheet was placed over the insulation to protect it from the weather.

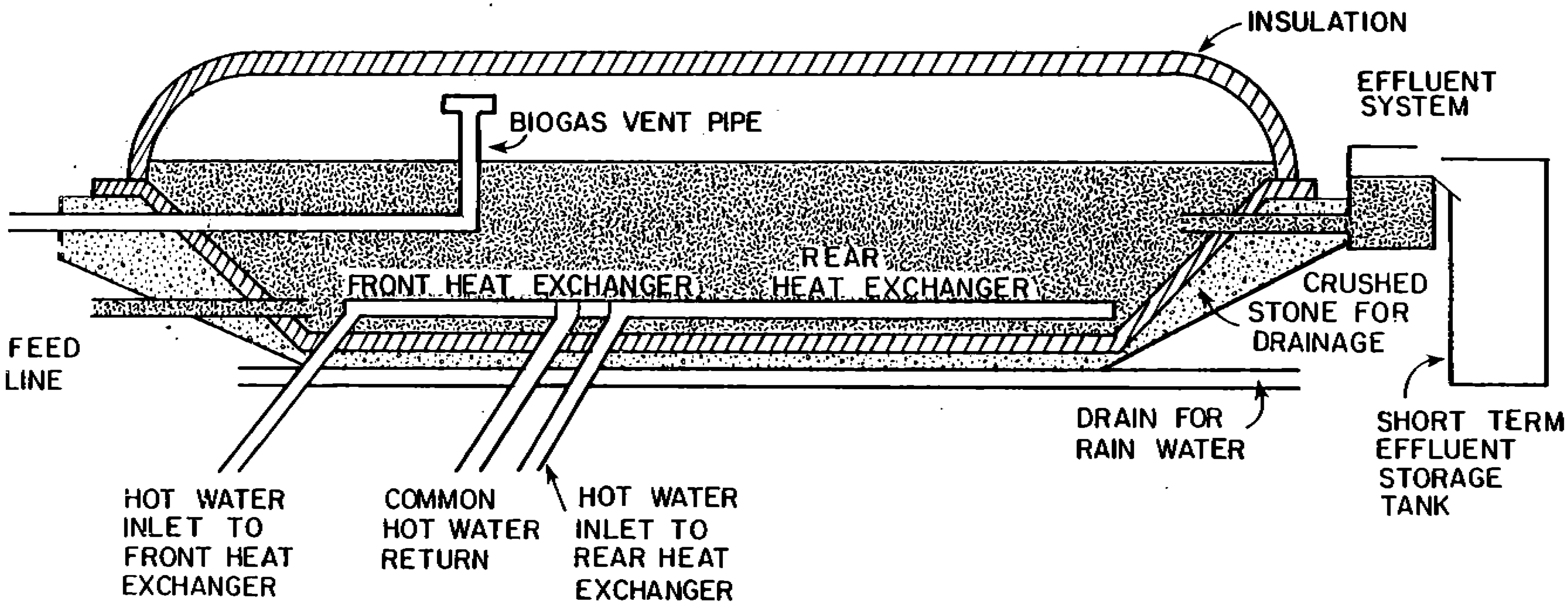


Figure 2.6. Cross section of the modified full scale plug flow digester.

This new cover material was anchored to the concrete collar and served as the means of biogas collection (Figure 2.7). The means of producing a gastight seal consisted of a system to clamp the XR-5 material between the concrete collar and a three inch channel iron. To insure that biogas could not escape the seal of the digester was operated with a liquid depth greater than the elevation of the clamping apparatus by 5 cm. A hard rubber gasket material (cow matting) was glued to the top of the concrete collar, which had half inch angle bolts preset every three feet. The cover material passed under one leg of a three inch channel iron, whose leg was protected by a half inch diameter PVC pipe cut in half lengthwise. The flexible cover material then passed around a half inch diameter rope and back beneath the channel iron. When the anchor bolts were tightened the XR-5 material was effectively pinched by the protected leg of the channel iron.

A single new steel biogas vent pipe (7.62 cm diameter) was installed vertically in the digester to replace the old venting system. A lower horizontal extension directed the biogas at a downward slope into the control room where it was available for use.

Manure from the digester exited the system through a new effluent system consisting of a manhole with adjustable weir. As shown in Figure 2.6, the effluent manure passed into this manhole (a 1 m^2 wooden structure having a depth of 1.5 m) through two PVC pipes 30.5 cm in diameter and overflowed into an adjustable wooden weir on the other side of the manhole. The weir setting determined the reactor depth, and thus the reactor volume, which throughout the study was maintained at 93.5 m^3. From the weir the manure passed into the short-term effluent storage tank as it did in the original design.

No changes were made to the digester heating system or to the means of charging the digester. However, the effluent baffle was removed from the original design and not replaced in the remodelled design.

II.A.4.c. Tracer Study

After the completion of the plug flow modifications in early July 1982, a study was conducted to interpret the hydraulic performance of the reactor. A homogeneous mixture of fine clay particles (532 kg) and dairy manure (8.1 m^3) were slug loaded to the digester. The manure flow rate and influent and effluent fixed solids concentrations were measured daily for 38 days following the clay addition on July 21, 1982. The increase in the effluent fixed solids concentration was monitored as the reactor was fed daily. It was assumed that an increase in the effluent fixed solids concentration prior to the theoretical hydraulic retention time (HRT) would be an indication of short circuiting. The theoretical HRT was defined as the average length of time the manure was in the reactor and was calculated using equation 2.1. The quantity of fixed solids in the influent or effluent from the digester was expressed in terms of the kilograms of fixed solids (material which remains after incineration at 550°C for 12 hours) per m^3 of manure (either influent or effluent). The actual

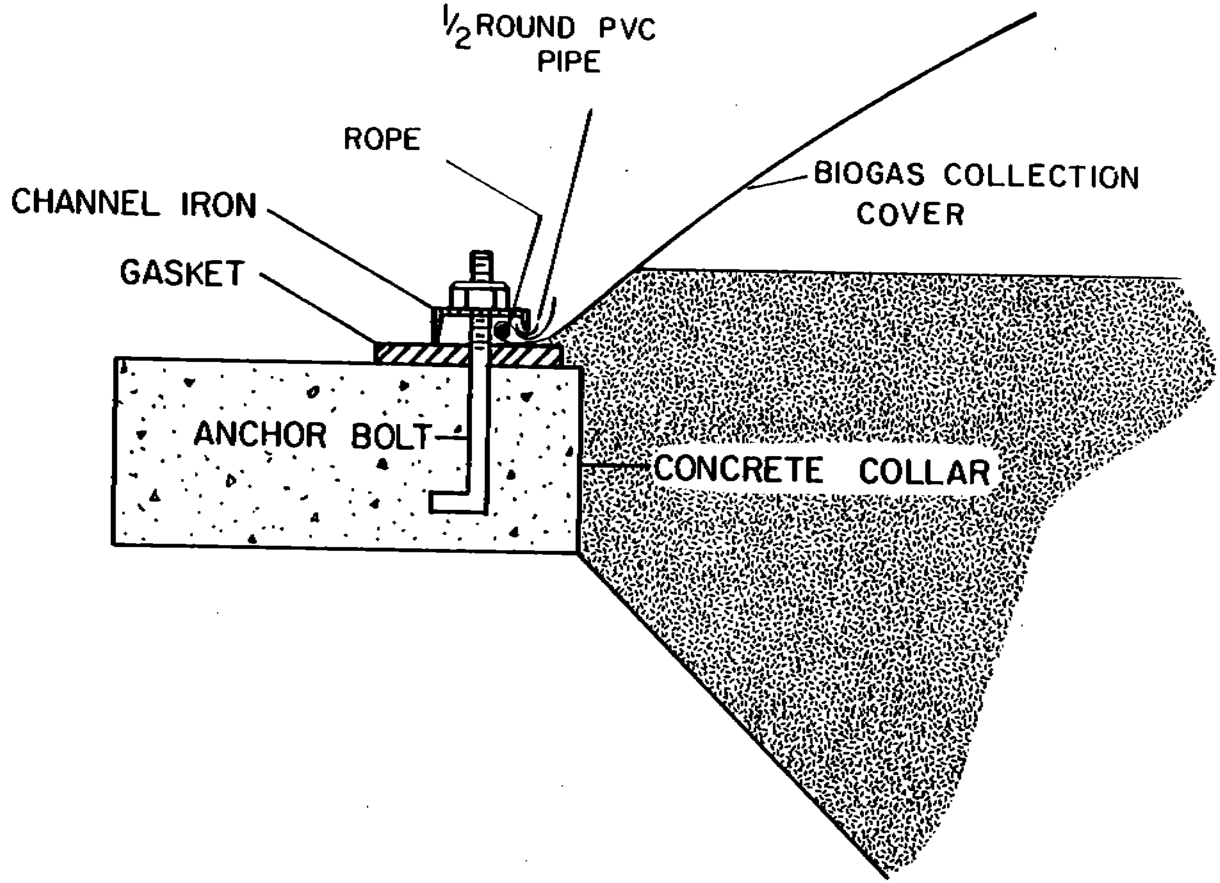


Figure 2.7. Illustration of the biogas collection cover anchoring system.

HRT was assumed to be the number of days for the maximum concentration of fixed solids to appear in the effluent.

$$HRT = RV/Q \qquad \text{Eq. 2.1}$$

where, HRT = the theoretical hydraulic retention time (days)
RV = the reactor volume (m^3)
Q = the manure flow rate to the reactor (m^3/d)

II.A.5. Series Operation

In an attempt to produce maximum rates and quantities of biogas from the dairy manure systems and to document an interesting design alternative, the completely mixed and plug flow digesters were operated in series from February 13, 1983, through June 14, 1983 (the termination date for all digester operations). Feed manure from the storage tank was pumped five times per week to the completely mixed reactor where the manure was retained for approximately five days. In this reactor the manure was preheated prior to being fed to the plug flow reactor. The completely mixed reactor effluent was pumped into the plug flow reactor five times per week, and the rates and quantities of biogas production in terms of the plug flow reactor volume were observed.

II.B. BIOGAS HANDLING EQUIPMENT

Biogas generated in each digester was collected and stored for use as a fuel in a cogeneration system, using the biogs handling system presented in schematic form in Figure 2.8. Biogas from each digester passed through a condensation trap, (Figure 2.1) which separated particulate water (and on occasion foam and digester liquids which were conveyed through the pipelines by the biogas during periods of digester foaming) and controlled the back pressure on each digester. Each digester also had an over pressure vent, constructed exactly as the traps but positioned in parallel (Figure 2.9). The water level in the vents was controlled such that biogas was vented to the atmosphere when the digester pressure exceeded 6 cm water column. The quantity of biogas produced from each digester was measured with a rotary positive displacement gas meter manufactured by Dresser Industries Inc.

The biogas was directed to a flexible low pressure storage tank, located on the roof of the engine control room (Figure 2.10). This tank, manufactured by the Good Year Aerospace Corporation, was a collapsible rubberized pillow tank having rectangular dimensions when empty of 6.1 x 6.7 m. The pillow tank provided a flexible means to store biogas at low pressure and provided a means of maintaining a constant back pressure on all the digesters. It also provided a mechanical means to control the operation of the compressors and baffled surges in biogas production rates which occurred during feeding.

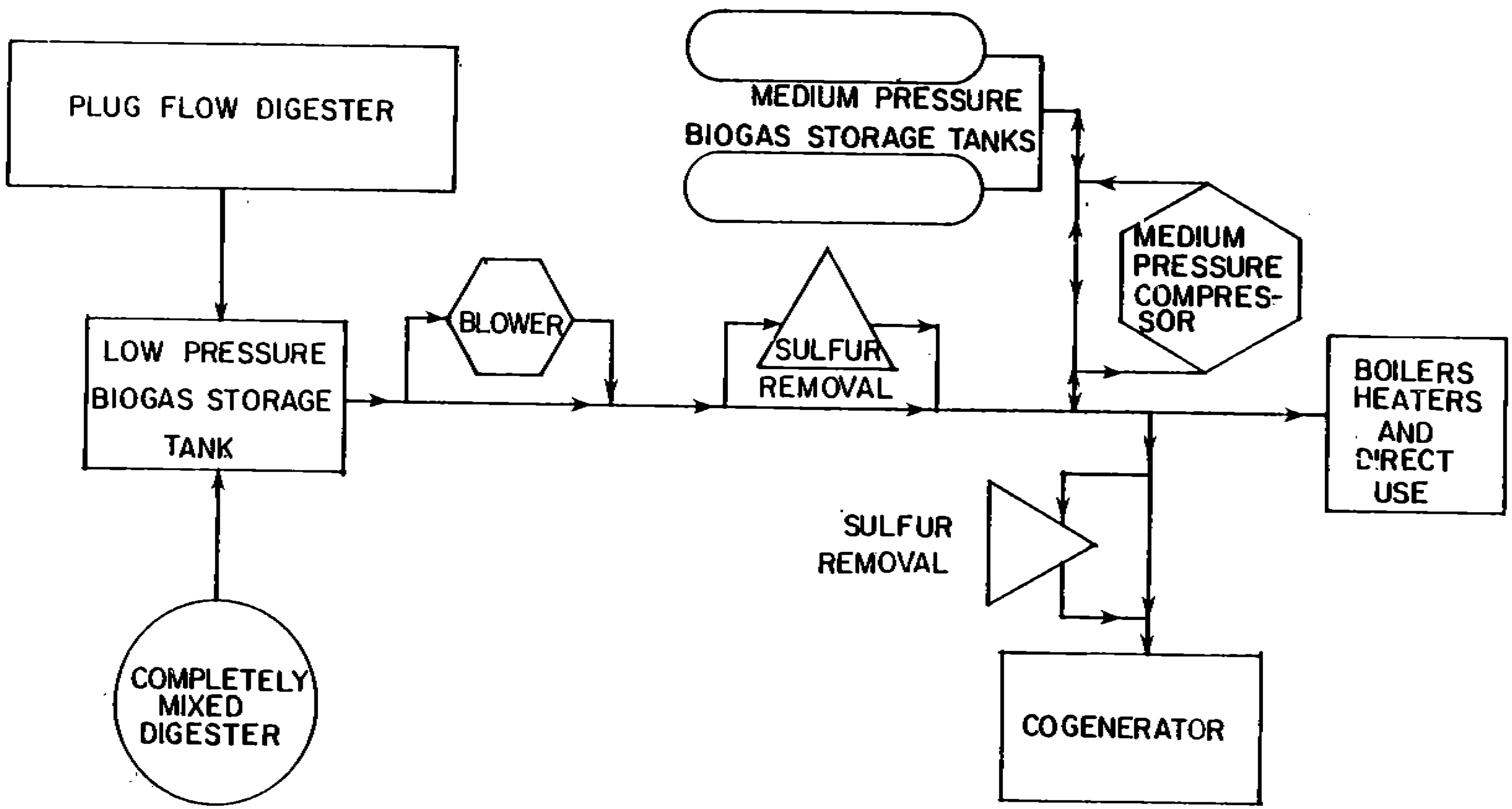


Figure 2.8. Schematic of the biogas collection, storage, and utilization system.

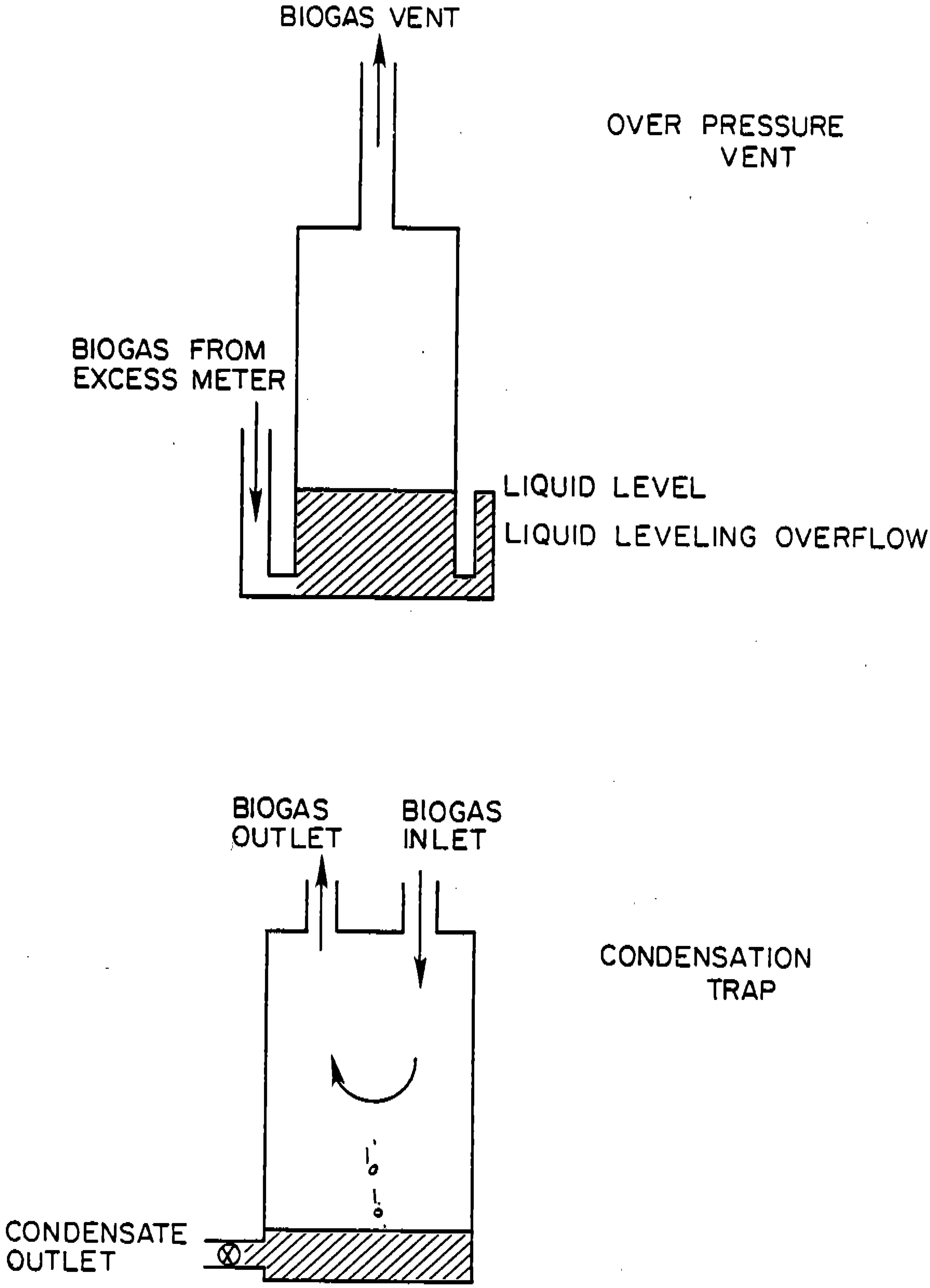


Figure 2.9. Cross sections of the condensation traps and over pressure vents used in both full scale systems to control the digester back pressure.

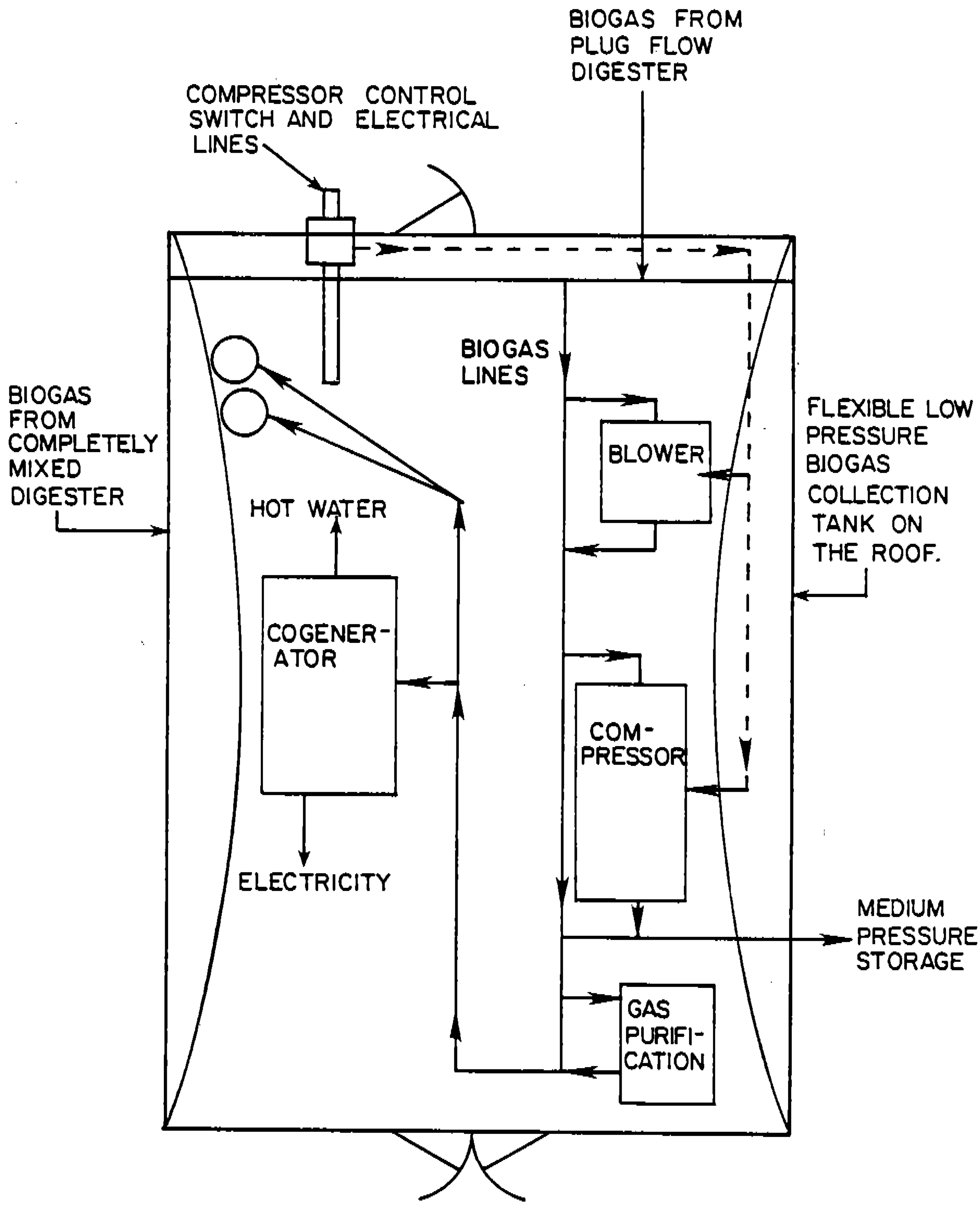


Figure 2.10. Plan view illustrating the location of the major biogas utilization components within the engine control room.

Once the tank was inflated such that the top was no longer in contact with the bottom, a constant back pressure due to the weight of the tank itself was exerted. A back pressure of 1 cm water column was maintained as the tank was inflated until the full capacity of the tank (38 m^3) was attained. This pressure was assumed to be the optimum and the lowest pressure at which to operate the digester systems.

Since the tank maintained the entire system at a constant pressure, a mechanical compressor switching device based on the height of the pillow tank was constructed to control the on/off cycling of the compressors. This mechanical device, shown in Figure 2.11, consisted of two mercury switches positioned such that the compressors were activated when the tank was inflated to a preset level and deactivated when the tank had deflated to a preset level.

Two compressors were used in the study. The first was a rotary vane compressor manufactured by Waukee Engineering Co. Inc. driven by a 0.6 kw electric motor and capable of an output pressure of 21 kPa and a volumetric output of 17 m^3/h. This compressor had an automatic built-in unloader and therefore was used to supply biogas directly to biogas driven equipment.

The second compressor was a two-stage piston compressor manufactured by Corken International Corp. driven by a 5.6 kw electric motor and capable of an outlet pressure of 200 psi and a volumetric output of 37 m^3/h. This compressor was used in series with the rotary vane compressor or alone but always was used to transfer biogas to the medium pressure storage tanks. Biogas entering this compressor was precooled with a water-to-gas heat exchanger such that the inlet temperature was always less than 15°C. Also, the biogas entering the compressor was passed through a particulate filter manufactured by Pall Trinity prior to compression for protection. The medium pressure storage vessel consisted of two used propane tanks each rated for a pressure of 250 psi and a capacity of 6.8 m^3.

All biogas equipment, including the cogenerator, boilers, laboratory, and heaters were operated at pressures (regulated using several pressure regulators manufactured by Fisher Controls) between 10 and 25 cm water column. The biogas was supplied either directly from the rotary vane compressor or from the medium pressure storage tanks.

For a short period all biogas was passed through a rectangular steel chamber (0.91 x 1.22 x 0.91 m) containing iron-impregnated sawdust referred to as an iron sponge. This material was used to remove sulfur compounds from the biogas. The Winslow Filter was used to remove some of the sulfur products for about six months.

II.C. COGENERATION SELECTION

An induction generator appears to offer the most appropriate generator choice for the type of electrical loads on a dairy farm. The electrical loads of a dairy have two peak use periods during milking that will last 6 to 12 hours per day. The peak periods may

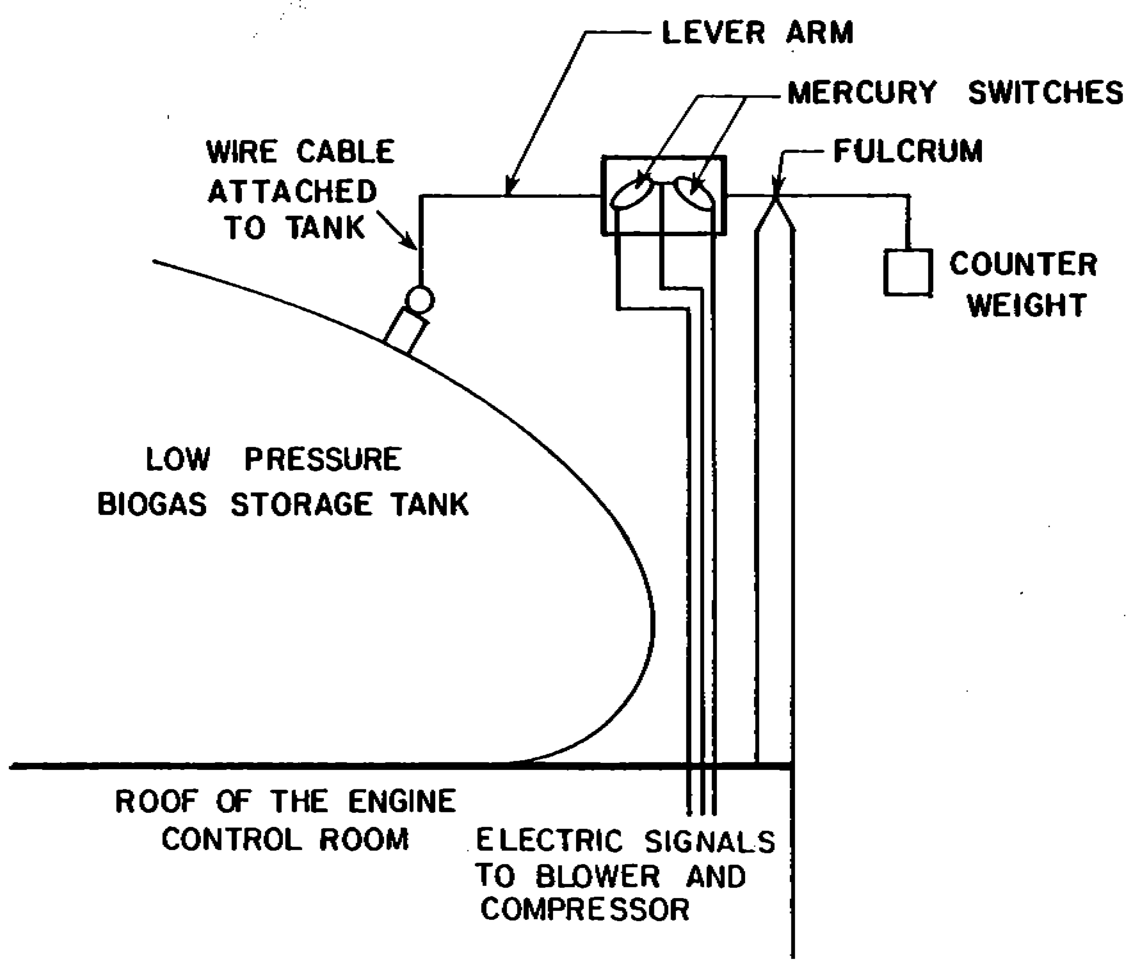


Figure 2.11. Illustration of the mechanical switch which controlled the cycling of the blower and compressor.

have an electrical demand 5 to 10 times greater than the rest of the day. Load leveling will not make appreciable changes in the electrical loads of a dairy. An engine generator designed to meet peak electrical loads and still operate during off-peak periods would run inefficiently during off-peak periods and require high initial capital expense. Therefore, an engine generator set operating at constant levels in parallel with the utility power supply would be the only feasible alternative.

Standard synchronous generators require extensive controls for paralleling with the utility. A 25 kW generator would require a $3,000 automatic synchronizer, a $500 voltage regulator with paralleling compensation, and a $1,350 VAR power factor controller (Kreuger, 1981). In addition, service on these components would be readily available to a farmer. An induction generator would require less expensive controls, including a relay protecting against reverse power and inappropriate voltages and frequencies to allow paralleling with the utility.

The major advantage of an induction generator is simplicity if paralleling with the utility is necessary. An induction generator is merely an electric motor. If driven below its synchronous speed, it draws power and acts as a generator. An induction generator must draw its reactive power needs from the utility power supply for setting up the rotating magnetic field in the stator. Since the generator is controlled by the utility, it can only produce power that is synchronous with the utility. Although the construction techniques of an induction generator are no different from an induction motor, this machine has seldom been used as a generator primarily because it is not capable of stand alone operation.

The major concern with an induction generator will be its performance and power factor at various loads. Presently limited background information exists related to the use of a single phase (necessary for most dairies) induction generator.

The heat recovery potential and utilization also needs further defining. Only engineering estimates exist for quality (temperature) and quantity of heat than can be captured with currently available heat exchangers on the engine coolant and exhaust systems under a dairy's conditions. Performance of the heat recovery equipment needs to be defined based upon agricultural heating loads.

Finally, the performance and operating costs of the engine need verification on biogas. The high octane rating of methane (120 relative to unleaded gasoline at 90) will allow the operation at higher compression. The low energy density of biogas will require approximately a 20% derating of the power output of the engine. Also, the corrosive nature of sulfur contaminants in the gas can conceivably cause deterioration of the engine oil, in the cylinders, and the exhaust heat recovery equipment. The importance of gas scrubbing to slow or prevent such problems also needs further verification. A complete package including engine, generator and heat recovery equipment was examined in this study.

A 25 kW cogeneration unit was selected for this project. It was assembled by Cummins Mohawk Diesel, Inc., of Syracuse, New York. The following description of the unit will be presented according to the following four major components: (1) engine; (2) generator; (3) heat recovery system; (4) controls.

The engine, manufactured by White Engines, Inc., of Canton, Ohio, was a combination of a series D-2300 diesel engine block and a series G-2300 spark ignition head. The heavier diesel engine block was selected with the hope that it would prove more durable. The pistons were a high compression design which produced a 10 to 1 compression ratio. The engine displacement was 3.70 liters (226 cubic inches) and carried a continuous duty power rating for natural gas of 36 kW (48 hp) at 1800 R.P.M. For additional engine specifications, refer to Appendix E. The engine utilized a gaseous positive pressure carburetor designed for low energy density gases.

The generator was a single phase, 240 volt, induction generator manufactured by Kato Engineering Company of Mankato, Minnesota. This unit utilized a brushless single bearing design. Because it is a 4-pole generator, its synchronous speed is 1800 R.P.M. The generator was rated by the company at 25 kW and carried a slip rating at this load of 2%. At full power the generator also carries a rated line current of 147 amperes, which would indicate a 71% power factor. (See Appendix E).

The engine's heat recovery system consisted of two separate heat exchangers. A water-to-water heat exchanger was employed to remove the heat from the engine cooling system. A Maxim heat recovery silencer provided the means for recovering some of the heat in the exhaust gases. The engine's original air-cooled radiator was removed and later employed as a backup heat dump.

A system of controls were included with the cogenerator to allow unattended operation of the unit. A complete listing of the unit's controls and their function is contained in Appendix E. Controls were provided to protect the engine against the following situations: (1) engine overspeed; (2) low engine coolant level; (3) high engine coolant temperature; (4) low oil pressure; (5) low gas supply pressure; and (6) inadequate fuel supply. Controls were also designed into the cogenerator to protect the generator against the following situations: (1) reverse flow of current to prevent the generator from acting as a motor and to assist in detecting faults within the generator; and (2) excessive current flow (greater than 150 amps).

In addition to the cogenerator, a mechanism to properly interface the cogenerator to the two anaerobic digesters and the dairy's electrical and water heating systems was also designed and installed. Schematic drawings of the electrical, hot water, and biogas systems are included in Appendix F.

The water heating system involved an engine coolant loop (1), a heat recovery and distribution loop (2), and a dairy hot water loop (3). Loop 1 was designed to transport excess heat from the engine's cooling system to a heat exchanger. The water in loop 2 recovered the heat from the engine coolant heat exchanger and the exhaust heat exchanger in that order. The flow in loop 2 then proceeded through several mechanisms for removal of the heat. The heat could be used in heating of two digesters or for preheating the water supply to the dairy's hot water system. If these uses did not remove a sufficient amount of heat, then heat was wasted either through a fan-cooled remote radiator or a temperature-actuated solenoid valve which dumped hot water. The priority for heat removal from loop 2 was given to the digesters first, dairy hot water system second, fan-cooled radiator third, and finally to the temperature actuated solenoid valve. Loop 3 preheated the water for the dairy's hot water heaters. The water circulated between a heat exchanger interface with loop 2 and a 1440-liter (350-gallon) storage tank. Preheated water was then supplied to the dairy from the storage tank upon demand.

During one phase of digester operation during the summer the heat dump was removed and the digester was used to absorb all excess heat. Temperature increases to 50°C occurred. Also the shift from mesophilic temperatures to the thermophilic range caused severe foaming in the digester.

The electrical system external to the cogenerator was relatively simple (see Appendix F, Figure F-4). A lockable manual disconnect switch always accessible to utility personnel and an additional 150 amp fuse and disconnect located at the point of connection to the farm electrical service were the only system components. The additional fuse protection was added due to our ability to connect additional energy consuming equipment to the circuit, thus requiring additional protection at a location other than the present circuit breaker on the generator. The circuit was connected to the farm electrical grid at a transformer. In addition, a 15 kVA capacitor bank was added to the electrical service in parallel with the generator to improve the power factor of the system. The only additional parts of the system involved electrical metering devices.

The biogas supply system provided the engine with gas at a regulated pressure of approximately 25 cm (10 inches) of water pressure. Shortly after the engine's installation, a filter for particulate matter was installed. The gas supply was generally saturated with moisture. Any condensation in the biogas supply was removed prior to passing through the high pressure compressor. Additional purification of the gas was dependent upon the type of test being performed. A Winslow gas conditioner (Appendix F, FIgure F-2) was installed for the last 1280 hours of cogenerator operation to alter the sulfur in the gas.

II.D. INSTRUMENTATION

An instrumentation system was installed that would provide an indication of the performance of the engine, generator, and the heat exchangers for heat recovery. The engine's instrumentation was designed to monitor fuel and air consumption, engine speed, oil temperature and spark timing. Fuel consumption was measured with a Roots gas flow meter. Fuel pressure, fuel temperature, and atmospheric pressure were also monitored to provide a correction for the volumetric fuel meter reading. Fuel quality was checked by means of Fyrite carbon dioxide auto analyzer and Gastec hydrogen sulfide gas sampler. The methane content of the biogas was assumed to contain only carbon dioxide and methane for volumetric calculation. During the performance testing of the cogenerator for the purpose of defining its thermodynamic characteristics, gas samples were analyzed by a gas chromatograph which directly indicated methane and carbon dioxide content.

II.E. TEST PROCEDURES

II.E.1. Analytical Methods

Both dairy manure digesters were monitored on a daily basis. Daily measurements included biogas production, reactor temperature, and manure flow rate. The Dresser biogas meters measured the cumulative quantity of biogas produced from each digester. These values were adjusted to standard temperature and pressure (STP) and expressed in terms of the volume of biogas produced per volume of reactor per day. Reactor temperatures were recorded daily, and the temperature in the temperature wells within each digester were expressed in degrees centigrade. The manure flow rate was determined by displacement in the short-term storage tanks. Average reactor temperature, manure flow rate, and biogas production rate was expressed as the mean of the daily measurements over a given time period, usually one week.

On a periodic basis, usually weekly, the influent and effluent pH and total solids (TS) and total volatile solids (TVS) were measured. The pH measurements were taken using a model 230 Fisher Accumet pH/ion meter, and the solids measurements were conducted according to Standard Methods (1975). Occasional measurements of the biogas carbon dioxide content was made using a model CND Dyrite CO_2 indicator manufactured by Bacharach Instrument Company. Carbon dioxide and methane contents in biogas were also occasionally determined with a series 550 thermal conductivity detector manufactured by GOW-MAC Instrument Company.

The digester loading rates were expressed in terms of the theoretical hydraulic retention time (HRT) in days and the organic loading rates (OLR) in grams of TVS loaded per liter of reactor per day. The removal rate (RR) was expressed in terms of the grams of TVS removed (influent TVS mass minus effluent TVS mass) per liter of reactor per day. The removal efficiency (RE) was expressed in percent as the ratio of grams TVS removed per gram TVS loaded. The biodegradable volatile solids (BVS) were the portion of the total volatile solids which could be biologically converted to biogas.

The expected quantity of biogas per gram of TVS destroyed was calculated, assuming that 0.35 liters of methane were produced per gram of total chemical oxygen demand (COD), that the COD to TVS ratio for dairy was 1.3, and that the average methane content of biogas was 60%. With these assumptions the expected biogas production rate was 0.76 liters of biogas at STP per gram of TVS destroyed.

Engine air consumption was checked by means of measuring the pressure drop across a 4.064 cm (1.6 inch) AMCA standard airflow nozzle mounted on a 208-liter (55-gallon) surge tank. A differential micromanometer capable of measuring pressure differentials to the nearest 0.0025 cm (0.001 inch) water column provided the pressure drop measurement across the nozzle. Atmospheric pressure and wet and dry bulb air temperatures were also monitored to provide a corrected airflow rate. Other parameters monitored include engine speed, timing, and oil temperature. Engine speed was measured with a magnetic pickup transducer in the proximity of the flywheel and read out with a Dynalco digital meter. Spark timing was checked with a standard timing light. A copper-constantan thermocouple and digital Omega meter monitored oil temperature just prior to its passing through the oil filter.

An Easterline Angus power survey meter was the basis for all electrical measurements. This unit provided a digital and printed readout of real power, apparent power, and power factor. Total accumulated energy production was monitored with the power survey meter and a standard utility watt-hour meter.

The hot water system was monitored for water flow rates, temperatures, and accumulated energy recovery or use. BTU meters provided accumulated indications of total water and heat energy flow. BTU meters were employed to evaluate the cogenerator's heat recovery system, the digester's heating system, and the energy delivery system for the dairy. Appropriately placed thermocouples were used to assist in assessing heat flow and other characteristics of the hot water system.

II.E.2. Cogenerator Analysis Program

The test program for the cogeneration system involved several separate series of tests and observations. The research program was designed to:

1. monitor the performance of the cogenerator, including
   a. critical spark system parameters,
   b. characteristics of the induction generator, and
   c. thermodynamic performance;

2. observe the effect of biogas fuel on lubricant and wear; and

3. determine maintenance schedules, operating procedures, and potential problems for long-term operation on biogas.

Although we had intended to test the engine at three different compression ratios, this was not accomplished. A complete description of the various test programs is contained in Appendix G.

The first series of tests determined the desirable operating parameters for the spark system which would minimize rough engine operation and misfiring. Tests were conducted for three different spark plugs representing different heat ranges (Champion J-6, J-8, and RJ-10) and two different spark plug gaps (0.043 cm and 0.076 cm). These tests were conducted at both a lean and rich fuel-air mixture and at a low and high load level (10 and 25 kw). Spark timing for all checks was set at the minimum retarded timing level that would produce maximum power output. Spark dwell angle was set according to the recommendation of the engine operator's manual for natural gas (31 to 34 degrees). The strip chart recording of electrical output of the generator provided a good indicator of smoothness of engine operation as well occurrences of misfiring.

A second series of tests checked the importance of spark timing over a wide range of engine loads, which would produce maximum power at a specific carburetion setting. Information was collected that would allow a prediction of minimum spark timing for loads between 5 and 25 kw and at lean and rich fuel-air mixtures. Again, spark dwell was maintained between 31 and 34 degrees.

A series of two separate tests were conducted to supply the information for predicting thermodynamic performance and induction generator characteristics. The first set of tests involved operation at loads ranging from 5 to 25 kW at three separate fixed fuel-air mixtures. Variations in the cogenerator's performance with load were of primary concern. The second series of tests was designed to explore the influence of fuel-air mixture on the cogenerator's performance. For these tests the generator's output was maintained at 25 kw and fuel-air mixture was varied.

Prior to each individual test, the electrical output and fuel-air mixture were set at the desired level. Spark timing was then adjusted to the minimum retarded setting at which maximum power could still be maintained for this particular throttle and carburetor setting. If necessary, electrical output would again be adjusted to the desired level. The unit would then operate for at least five minutes to allow it to reach steady state condition before the test period would begin. A 60-minute test period would follow. All cumulative meter readings, such as electrical production, were an aggregate of this 60-minute period. All instantaneous readings, such as temperature, were checked three times at equally spaced intervals. Specific parameters measured and other important test information are contained in Appendix G.

The long-term engine performance was also monitored. The primary concern of this operation was the effect of raw and scrubbed fuel on the crankcase lubricant and the resulting wear within the engine. Oil samples were collected at the time of oil change. In addition, oil samples were taken at 50-hour intervals over a 250-hour oil change interval during operation with the raw and scrubbed biogas. More than 1200 hours were accumulated for both operation on raw biogas and on biogas passing through a Winslow gas conditioner, resulting in a total operation period of more than 2500 hours. Hydrogen sulfide levels were also monitored at regular intervals over the duration of the project. Records were also kept of operating hours, electrical and hot water production, and maintenance needs of the cogenerator.

To assess potential engine wear problems, the engine was torn down for biogas. Representatives of White Engine Company, Cummins Mohawk Diesel, Inc., and the Cornell research team were present during the disassembly of the engine. The initial operation of the engine on raw biogas lasted for 1220 hours and was followed by only a partial disassembly of the engine. The second test period involved operation on biogas that had passed through a Winslow biogas filter. This second period extended over a 1280-hour period and was followed again by a partial disassembly of the engine. Because of the engine failure that had occurred, the engine was returned to White Engine's facilities in Ohio for additional analysis and observation.

One final series of tests was employed to determine heat transfer rates of the digester heating system and the potential effect of using 85° to 90°C water in the digester heating grid. This effort involved monitoring of the heat transferred to the digester over an eight-hour period. Digester temperatures and inlet and outlet water temperatures for the heating system were also monitored over this period of time. These tests were originally to be conducted at one month intervals, but this goal was not entirely accomplished.

The primary elements measured during the various test programs included air consumption, fuel use, electrical output, heat recovery, and various other engine parameters. In addition, several environmental factors, including barometric pressure and dry and wet bulb air temperatures, were monitored. The test equipment for these parameters was described in Chapter III. The following information details the calculation procedure for analyzing the raw data.

A prediction of air consumption of the engine was based upon measurement of the pressure drop across a nozzle. Airflow passed through a nozzle and into a surge tank before entering the engine. The surge tank was designed to maintain constant flow at the nozzle. The equation for calculating airflow is:

$$w = 3.957 C F F_a Y_a d^2 (h_w/v)^{0.5} \qquad \text{Eq. 2.2}$$

where,

- w = airflow rate in kilograms per hour at 20°C and standard atmospheric pressure.
- C = nozzle coefficient of discharge.
- F = velocity of approach factor. $F = 1/(1-B^4)^{0.5}$ where B is the ratio of nozzle diameter to pipe diameter. In this situation $B = 0$ and $F = 1$.
- F_a = thermal expansion of nozzle. Assumed to be 1 for temperatures less than 38°C.
- Y_a = adiabatic expansion factor for flow nozzles; $Y = 1$ for this study.
- d = nozzle diameter in inches.
- h_w = differential pressure in centimeters of water column.

v = specific volume of air in cubic meters per kilogram. Specific volume of air was corrected for temperature, barometric pressure, and moisture content according to standard psychrometric procedures.

The following equation for calculation of nozzle coefficient of discharge was selected (Benedict, 1964).

$$C = 0.19436 + 0.152884\ (\ln R_d) - 0.0097785\ (\ln R_d)^2 + 0.00020903\ (\ln R_d)^3 \qquad \text{Eq. 2.3}$$

R_d represents the Reynolds number of the air. Since the calculation for Reynolds number is dependent on an estimate of airflow rate and the airflow rate calculation requires a coefficient of discharge, these two equations are dependent on each other. Airflow rate and the nozzle coefficient were calculated by an interaction process which required that the assumed value for nozzle coefficient and the final calculated value be within 0.1 percent of each other.

To allow for calculation of biogas consumption rates, volumetric gas meter readings were done over specific periods of time. To correct for pressure and temperature variations from a standard of 20°C and 101.3 kPa, information on biogas pressure and temperature and barometric pressure was collected. Volumetric meter readings were corrected according to the following formula:

$$V_s = 2.89 V_m (P_b + P_g)/T_g \qquad \text{Eq. 2.4}$$

where,

V_s = volume of biogas consumed at standard conditions.
V_m = volume of biogas consumed as measured by volumetric meter.
P_b = barometric pressure in kPa.
P_g = gage pressure of biogas in kPa.
T_g = temperature of biogas in degrees Kelvin.

A determination of the actual methane content of the biogas was based upon samples analyzed by a gas chromatograph for all performance studies. The mass of methane consumed was estimated according to the following procedure:

$$m_s = V\ P/v \qquad \text{Eq. 2.5}$$

where,

m = mass of methane consumed in kilograms.
P = percent methane.
v = specific volume (cubic meters/kilogram) of biogas or methane at standard pressure and temperature. For methane, v = 1.50.

The correlation between estimating air-fuel ratio (AF) and equivalence ratio (ER) is as follows:

AF = mass of air / mass of fuel
ER = stoichiometric AF / Actual AF

For all calculations in this report, the mass of the fuel is considered to be just the mass of the methane consumed. The stoichiometric ratio for air-methane mixture was assumed to be 17.2 (Obert, 1973).

Estimates were made for energy consumption, energy production, and thermal efficiency of the cogenerator. The estimates of energy consumption (EC) by the engine were based upon the lower heating value of methane (50050 KJ/kg or 33400 KJ/m^3) and the following formula:

$$EC = m\ 50050 \qquad \text{Eq. 2.6}$$

The electrical efficiency (EE) and heat recovery efficiency (HRE) estimates are expressed as a percentage and calculated as follows:

$$EE = [(kWh \times 3600) / (m \times 50050)] \times 100$$
$$HRE = [(BTU \times 1.055056) / (m \times 50050)] \times 100 \qquad \text{Eq. 2.7}$$

where,

kWh = kilowatt-hour production by generator,
BTU = BTU meter reading.

Other electrical parameters requiring calculation from the raw data include percent slip and reactive power. Actual power, apparent power, and power factor were directly reported by the power survey meter. Percent slip is a relative comparison of actual generator speed (1800 rpm for our generator) to synchronous speed by the following formula:

$$\%\ Slip = \frac{Actual\ rpm - 1800}{1800} \qquad \text{Eq. 2.8}$$

Reactive power characteristics of our generator were calculated according to the following procedure:

$$P_r = (P_{ap}^2 - P_{ac}^2)^{0.5} \qquad \text{Eq. 2.9}$$

P_{ac} = Actual power
P_r = Reactive power
P_{ap} = Apparent power

The oil analysis portion of this project was performed by Kendall Refining Company. As part of their normal oil analysis program for all Kendall customers, oil samples are subjected to a series of analytic and spectrographic analysis tests. The analytic measurements included checks of viscosity and water, antifreeze, fuel, solids and varnish contamination levels. The spectrographic analysis provides an indication of wear metal levels in the oil. Wear metals were reported for iron, copper, lead, aluminum, silica, chrome, tin, sodium, and boron. In addition, oil total base number was analyzed and reported by Kendall.

In addition to Kendall, two other companies assisted in the analysis of various aspects of this project. Winslow Filtration provided a chemical analysis of the Winslow gas conditioner after 1280 hours of operation in our biogas supply line to the engine. No information was provided by Winslow as to the procedure for this chemical analysis. White Engine Company participated in the wear and failure analysis of the engine. Their testing included measurements of physical component size, visual observation, and some metallurgical testing.

CHAPTER III

RESULTS

III.A. INTRODUCTION

III.A.1. Biogas Generation

III.A.1.a. Background

Beginning in 1974, the research team at Cornell University began to define the technical, practical, and economic feasibility of energy production using anaerobic fermentation of agricultural residues available on small dairies (40 to 100 cows) and medium sized beef feedlots (1000 cows) (Jewell et al., 1976). This study determined that few improvements had been made in the technology of digester design since the mid-1930's. A comprehensive study followed to provide an indication of the improvement to the technology which could be achieved with emphasis on the fermentation process itself, as well as its by-products (Jewell et al., 1978, 1980). This study defined the potential of improving anaerobic fermentation with the development of a simplified low cost reactor which could supply a cost-effective alternative to energy generation from dairy cattle manure.

After defining the design requirements in comprehensive bench scale operations for a period of three years, a pilot reactor (with a three cow per day capacity) was constructed and operated continuously for two years. The positive data supplied by these extensive tests provided the technical basis to design a full scale plug flow system. Such a unit was constructed at the Cornell University dairy in 1977 to digest the manure from 65 cows per day (volume of 35 m^3). A control reactor of the same size using completely mixed technology was also built and was operated in parallel under the same conditions as the plug flow unit. This study was the first to compare the major design options for anaerobic fermentation in parallel full scale systems (Jewell et al., 1980).

Following this comprehensive comparative study, the two full scale digesters were operated for an additional two years to provide long-term observations on operational reliability and material durability (Jewell et al., 1981).

Operation of the two dairy manure full scale digesters continued; however, the emphasis of the Cornell research was redirected toward a new energy generating process called "dry fermentation." In this process crop residues, special crops, and/or large energy plantations would provide the substrate for anaerobic fermentation at a solids concentration higher than that at which water will drain from the substrate. After successful bench and pilot scale investigations, a 110 m^3 mesophilic dry fermentor was operated at the Cornell University dairy facility (site of the two full scale dairy manure digesters) using wheat straw as the substrate (Jewell et al., 1982).

III.A.1.b. Digester Operation

All operating experience indicated that the plug flow system was a more effective design for slurry digestion than the more costly completely mixed conventional alternative. At longer hydraulic retention times (HRT) (approximately 30 days corresponding to an organic loading rate of 1.5 grams of biodegradable volatile solids per liter of reactor per day (gm BVS/ℓ-d)), more than 90% of the biodegradable organics were converted to biogas in the plug flow design, whereas less than 80% were converted under identical conditions in the full scale control system (Figures 3.1 and 3.2).

As shown in Figure 3.3, the rate of organic conversion in the plug flow system was also greater than that of the conventional design. At these higher removal rates the total biogas production and thus the gross energy production from the plug flow digester were also greater than the conventional completely mixed design (Figures 3.4 and 3.5). The plug flow unit was also much easier to maintain and to modify during problem periods (Jewell et al., 1980 and 1981).

III.B. FULL SCALE DIGESTER OPERATION

Operation of two full scale anaerobic digesters began in 1977. This study was conducted to further document the performance of these digesters, to document the construction and operation of individual components of a biogas handling system, and to define the performance of a cogeneration system capable of utilizing the biogas energy.

The two digesters (a completely mixed control reactor and the Cornell design plug flow reactor) were operated continuously for 1875 days and 1839 days, respectively, from April 27, 1978, to June 14, 1983. The results presented in this chapter were summarized from data accumulated over the period from December 1, 1980, until termination of digester operation on June 14, 1983, a period of 926 days. During this period the two digesters were operated primarily to provide sufficient quantities of biogas to measure the performance of the biogas storage and utilization systems; however, the performance of each digester was defined under eight loading conditions ranging from 0.4 to 16.7 grams TVS per liter reactor per day.

III.B.1. Digester Performance

The dairy manure used as feed to both full scale digesters was obtained from the second barn at ASTARC, which was also the digester site. The second barn was a free stall barn which was mechanically scraped once per hour and which housed between 80 and 140 cows. The manure, produced from cows in all stages of lactation, was conveyed to a 142 m^3 concrete storage tank for transfer to the digesters once per day. No bedding was used in this barn until the final year of the study, at which time small quantities of sawdust and wood shavings were present in the manure at concentrations of approximately 0.5 kg (dry) per cow per day.

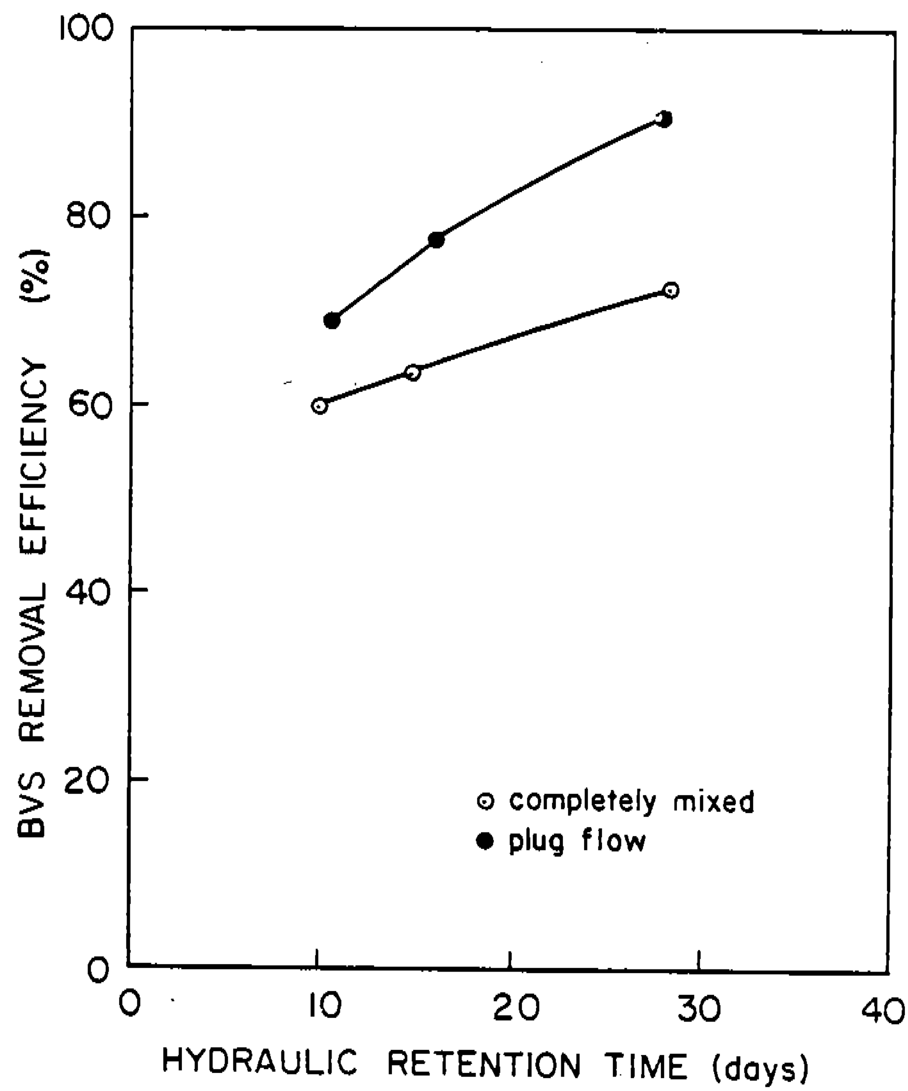


Figure 3.1. Effects of hydraulic retention time on the removal of biodegradable volatile solids (summarized data from Jewell et al., 1980).

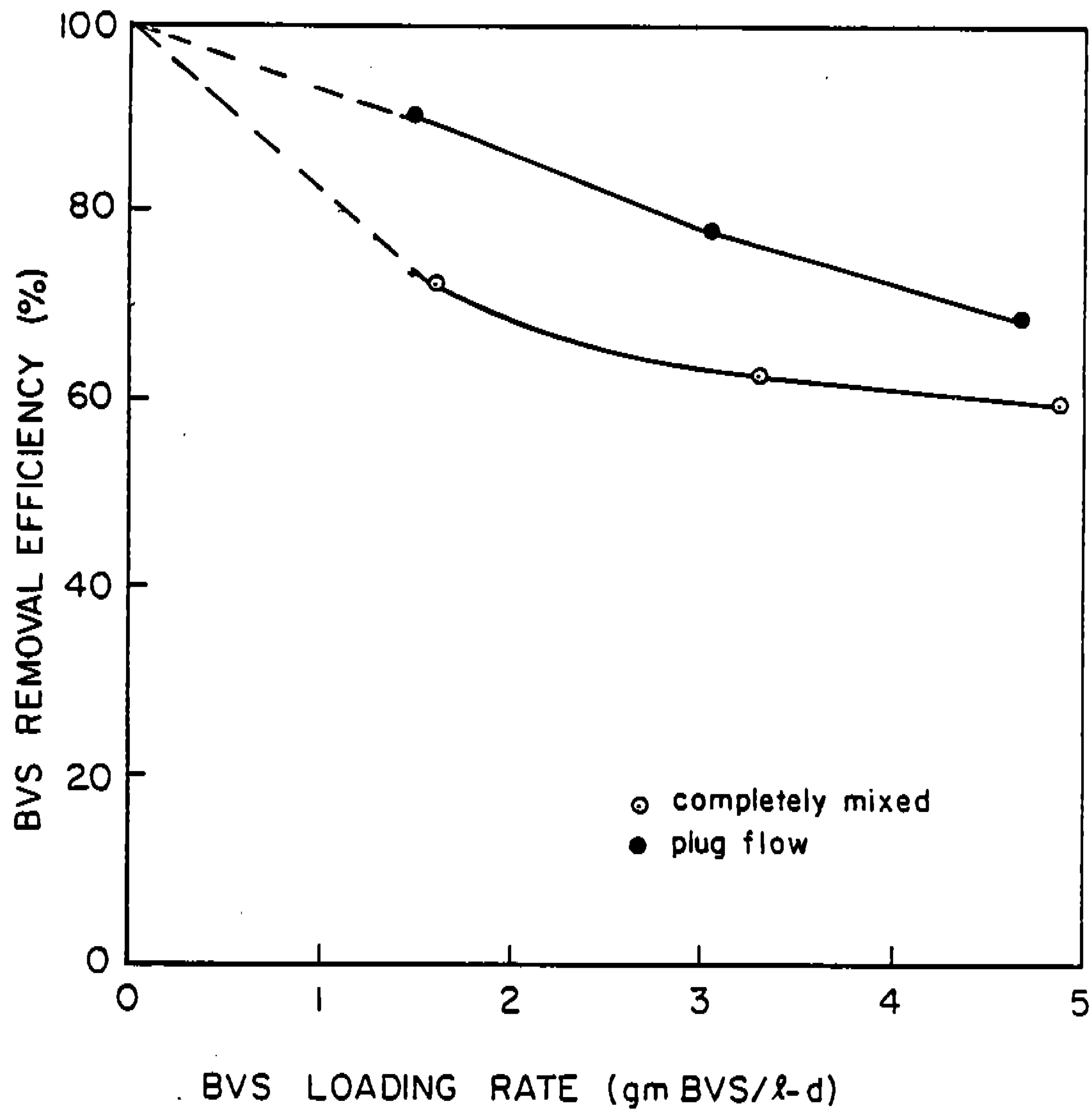


Figure 3.2. Effect of organic loading rate on the removal of biodegradable volatile solids (summarized data from Jewell *et al.*, 1980).

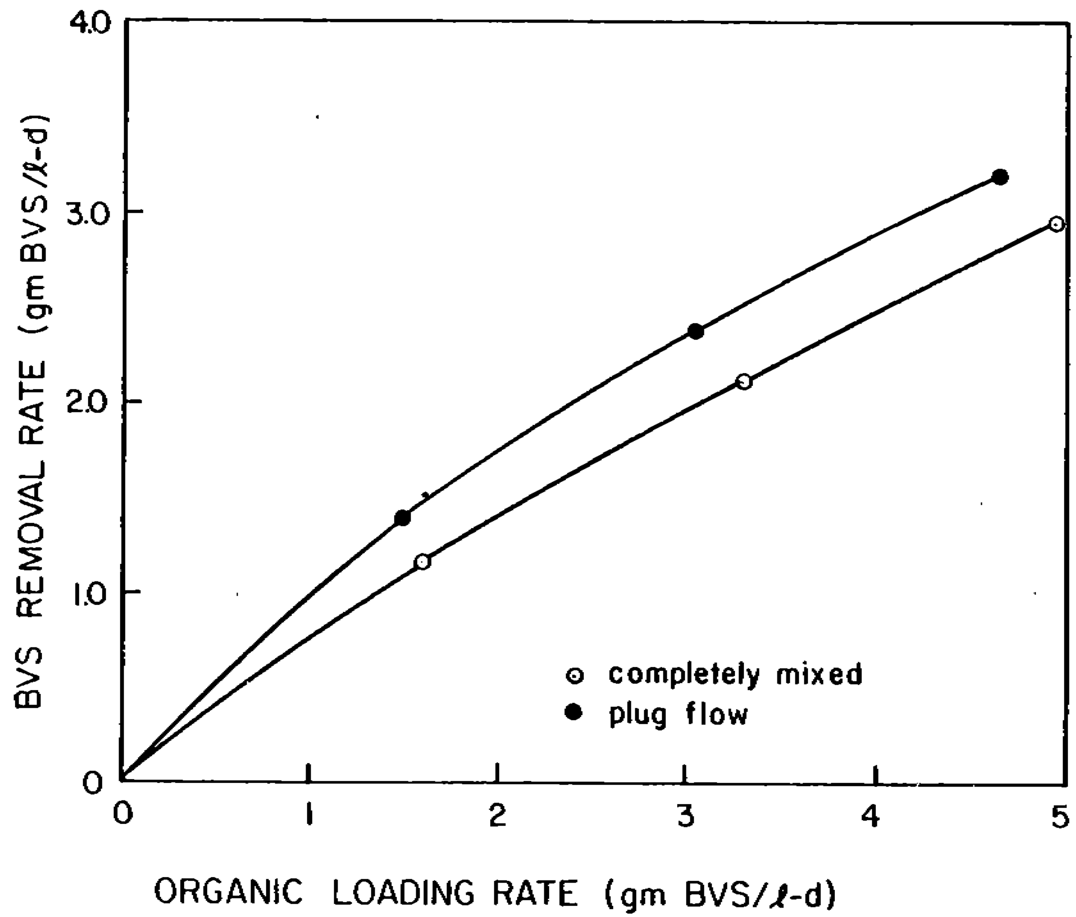


Figure 3.3. Effect of organic loading rate on the rate of volatile solids removal (summarized data from Jewell et al., 1980).

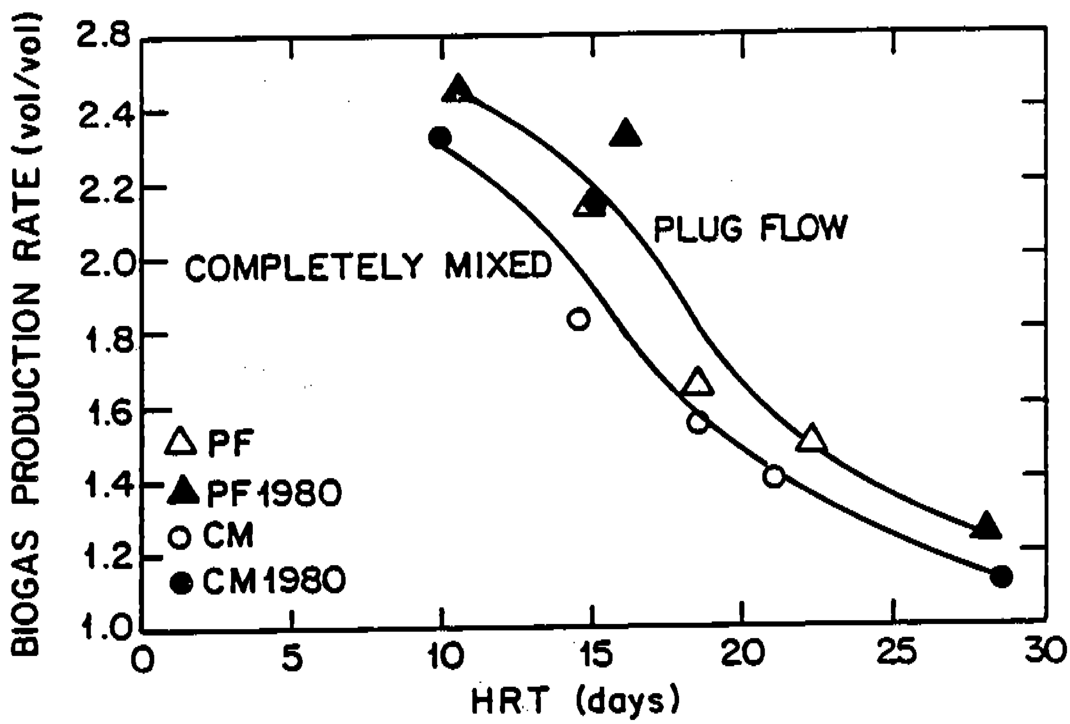


Figure 3.4. Effects of hydraulic retention time on biogas production (from Jewell et al., 1981).

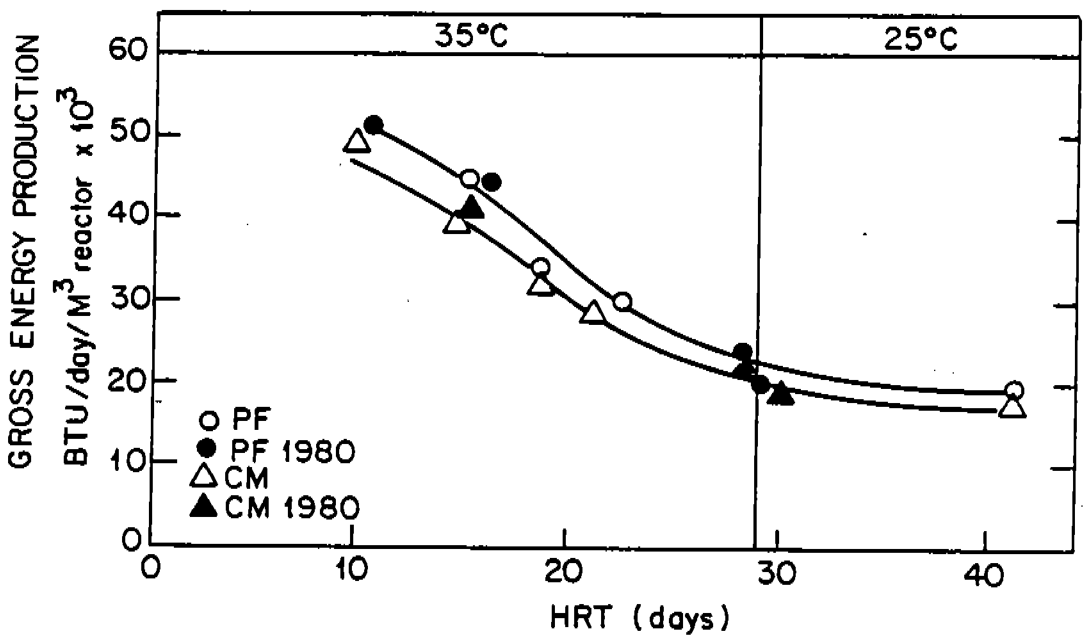


Figure 3.5. Normalized gross energy production rates achieved by full scale digesters operated at temperatures of 25°C and 35°C (from Jewell et al., 1981).

As shown in Table 3.1, as much as 7 m^3 of dairy manure were processed daily by the combination of both digesters. The average dry matter content of the manure throughout the study was 11.6%, of which 88.0% was volatile. The average pH of the feed manure was 6.7.

The energy content of the ration fed the dairy animals was determined by lactation stage. Thus the variability of the animal lactation stages affected the biodegradability of the manure produced. The biodegradability of the manure was estimated from several batch tests with the full scale completely mixed unit (Table 3.2). The biodegradability was about 38 percent of the volatile solids.

At the point of initial digester start-up in 1978, both full scale digesters were operated in parallel; i.e., each reactor was fed the same feed manure. This mode of operation continued during this study until June 25, 1982. At that point the plug flow reactor was remodeled, increasing the reactor volume from 40 m^3 to 93.5 m^3. Both reactors continued parallel operation on July 8, 1982 until February 13, 1983. At that point parallel operation was terminated and series operation began. Feed manure from the storage tank was fed to the completely mixed digester, and its effluent was the feed to the plug flow digester. On June 14, 1983 operation of both digesters was terminated. A summary of the operation of each digester throughout the study at intervals of approximately one week is presented in Appendix A.

III.B.2. Parallel Operation

From the operational data in Appendix A results were calculated at each interval for which complete solids, biogas, and manure flow rate measurements were available. These results, presented in Appendix B, were organized according to ranges of total volatile solids organic loading rates to form the eight loading conditions presented in Appendix C for each reactor. An average value of each measured component at each loading condition was determined and used to calculate the digester performance summary presented in Table 3.3.

As can be seen in this table, organic loading rates (expressed as grams of total volatile solids loaded per liter of reactor per day, or g TVS/ℓ-d) from 0.4 to 16.7 were examined at corresponding hydraulic retention times (HRT, days) of 6.4 to 295 days.

The plug flow digester operated at slightly higher rates of total volatile solids removal (expressed as grams total volatile solids removed per liter of reactor per day, or g TVS/ℓ-d), as shown in Figures 3.6 and 3.7. At an organic loading rate of 7 g TVS/ℓ-d, corresponding to an HRT of 16 days, the plug flow digester was capable of removing 2.9 g TVS/ℓ-d while the completely mixed reactor operated at 2.4 g TVS/ℓ-d. These higher rates of TVS removal also resulted in more efficient removal of the TVS, as shown in Figures 3.8 and 3.9.

The rates of biogas production from both digesters were not as consistent at the TVS removals at the various loading rates (Figures

TABLE 3.1. SUMMARY OF FEED DAIRY MANURE CHARACTERISTICS

Feed Rates (m^3/d)	0 to 7
Total Solids Conc. (% of wet wt.)	9.8 to 13.0; AVG = 11.6
Total Volatile Solids Conc (% of dry wt.)	85.3 to 90.3; AVG = 88.0
pH	6.3 to 7.4; AVG = 6.7

TABLE 3.2. DAIRY MANURE BIODEGRADABILITY AS DETERMINED FROM OPERATION OF THE FULL SCALE COMPLETELY MIXED DIGESTER AT HRT'S IN EXCESS OF 390 DAYS

HRT (days)	--INFLUENT--- TS_O (%)	VS_O (%)	--EFFLUENT-- TS_E (%)	VS_E (%)	Biodegradability (% TVS)
590	11.5	88.6	7.5	82.9	38
393	12.7	89.5	8.2	84.0	38
442	11.6	89.3	7.7	83.8	38

$$\text{TVS BIODEGRADABILITY (\%)} = 100 - \frac{VS_E(100-VS_O)}{VS_O(100-VS_E)} \quad \text{E 5.1}$$

TABLE 3.3. SUMMARY OF RESULTS FROM OPERATION OF THE FULL SCALE PLUG FLOW AND COMPLETELY MIXED DIGESTERS

CONDITION	FLOW (m^3/d)	-----INFLUENT----- TS (%)	TVS (%)	pH	---EFFLUENT--- TS (%)	TVS (%)	pH	HRT (days)	BIOGAS (v/v/d)	OLR (g/ℓ-d)	RR (g/ℓ-g)	RE (%)	GAS/TVS (ℓ/g)	BIOGAS (v/v/d)
P-1*	0.8	11.1	87.9	6.8	7.7	83.8	7.5	53.3	0.8	1.8	0.6	34.0	1.33	0.5
P-2	1.2	10.6	87.9	6.6	7.5	84.3	7.6	33.9	1.0	2.7	0.9	32.6	1.13	0.7
P-3	1.5	11.0	86.4	6.5	6.9	83.1	7.7	27.6	0.8	3.4	1.4	40.1	0.55	1.0
P-4	1.8	12.0	88.1	6.8	7.9	82.9	7.7	22.2	1.2	4.8	1.8	38.5	0.68	1.4
P-5	2.1	11.6	87.2	6.8	8.0	83.2	7.8	18.9	1.0	5.4	1.8	34.1	0.55	1.4
P-6	2.6	12.0	89.2	NA	7.5	83.1	7.5	15.4	2.5	7.0	2.9	42.0	0.85	2.2
P-7	3.0	11.4	89.2	6.6	7.5	83.2	7.3	13.4	2.0	7.6	2.9	38.4	0.69	2.2
P-8	3.3	12.1	86.3	NA	8.9	83.3	NA	12.1	0.8	8.6	2.5	29.4	0.33	1.9
C-1**	0.1	12.1	88.8	6.6	8.0	83.6	7.7	295.0	0.6	0.4	0.1	37.8	4.49	0.1
C-2	0.7	11.0	87.9	6.7	8.1	83.8	7.7	54.5	0.7	1.8	0.5	25.3	1.60	0.3
C-3	0.9	11.0	88.0	6.7	8.2	84.3	7.6	37.7	0.9	2.6	0.7	28.1	1.18	0.5
C-4	1.2	11.4	87.6	6.9	8.5	83.4	7.6	30.0	1.0	3.3	1.0	28.5	1.04	0.7
C-5	1.6	11.5	87.9	6.9	8.6	83.5	7.8	21.9	1.1	4.6	1.3	29.0	0.85	1.0
C-6	1.7	12.5	88.8	6.8	8.7	84.0	7.8	20.8	1.0	5.3	1.8	34.3	0.53	1.4
C-7	2.2	12.2	88.5	NA	8.3	83.8	7.5	16.3	1.4	6.6	2.4	35.8	0.61	1.8
C-8	5.6	12.1	88.2	6.9	10.1	86.4	7.2	6.4	1.7	16.7	2.6	15.7	0.27	2.0

*P = the plug flow digester and reactor volume, 40 m^3

**C = the completely mixed control digester reactor volume, 34.5 m^3

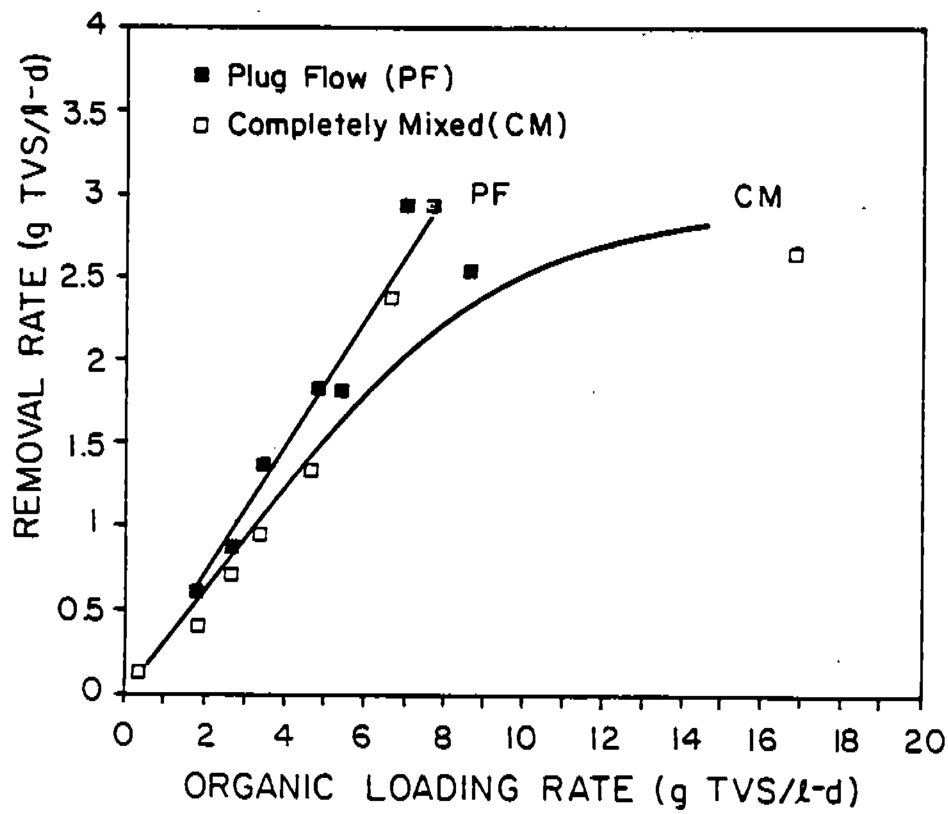


Figure 3.6. The effects of the TVS organic loading rate on the rate of TVS removal.

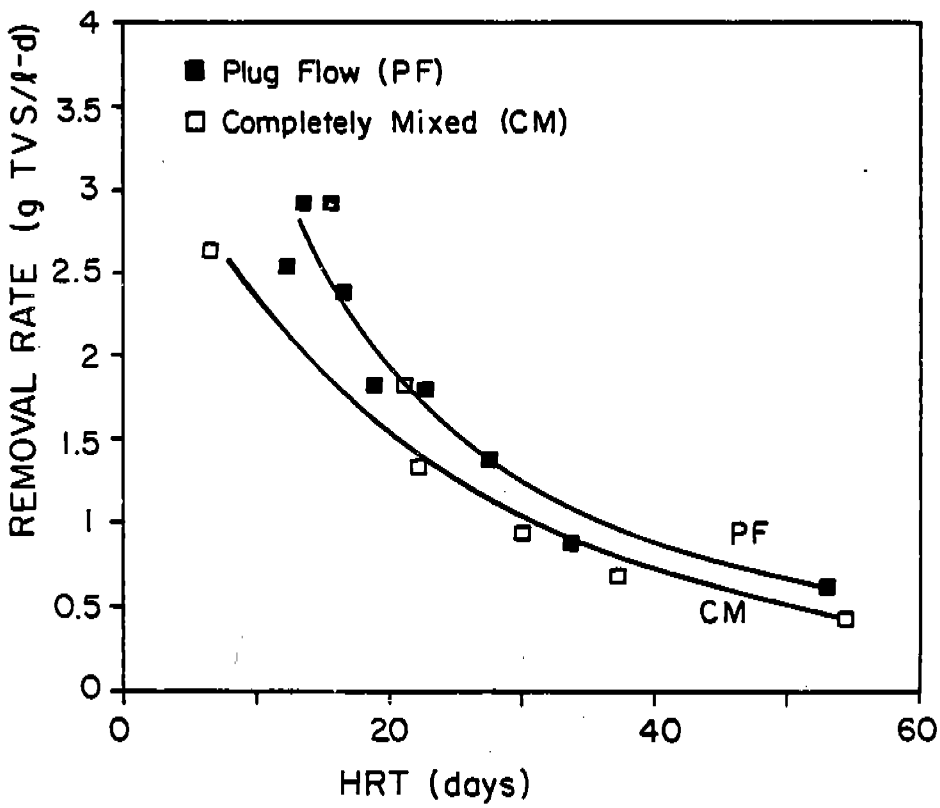


Figure 3.7. Effects of HRT on the rate of TVS removal.

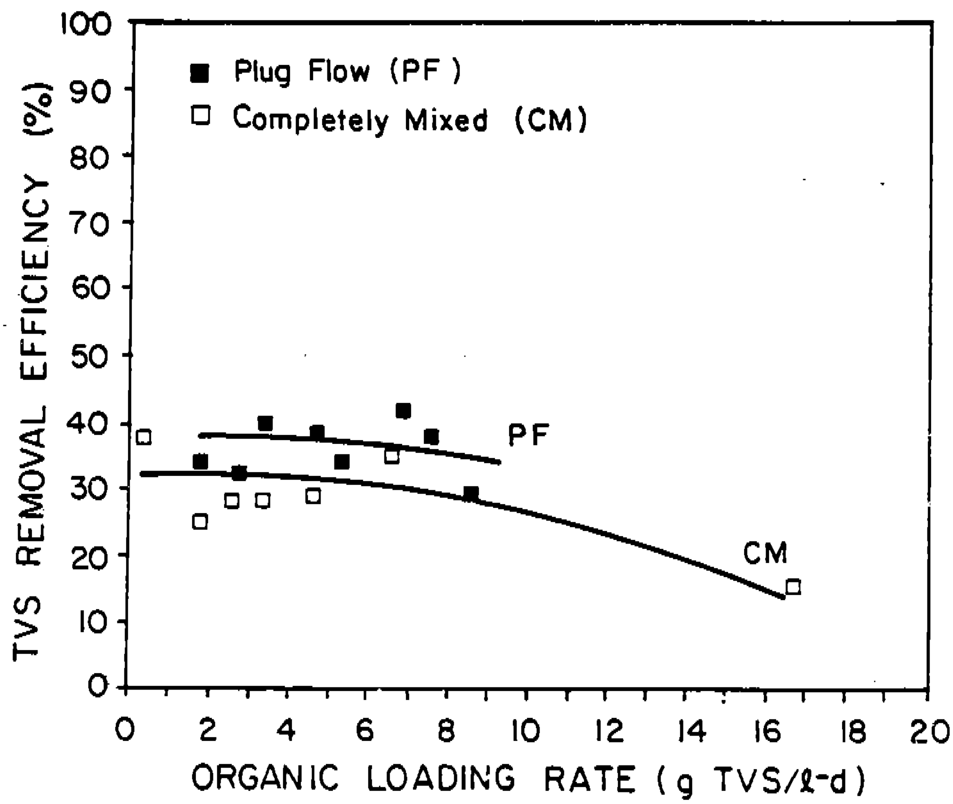


Figure 3.8. The efficiency of TVS removal versus the TVS organic loading rate.

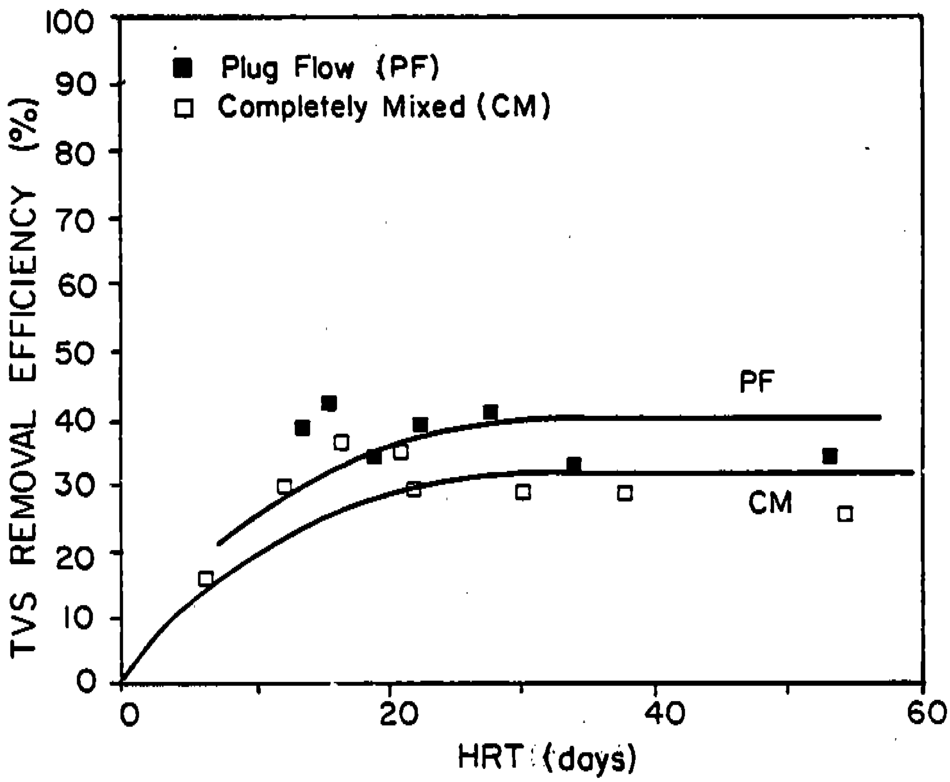


Figure 3.9. TVS removal efficiency versus HRT.

3.10 and 3.11). Both digesters, designed to be short-term research vessels, had been operating continuously for nearly three years, and problems were known to exist with the biogas collection systems. However, as shown in Figure 3.12, the relationship between the rates of biogas production were quite consistent with the rates of TVS destruction. The theoretical biogas production rates presented in this figure represent the calculated biogas production rates expected from the two digesters, based on the removal of TVS.

III.B.3. Results After Digester Modifications

In June of 1982 attempts to upgrade both digesters using minimal capital and manpower were made. The main focus of the modifications was to increase the plug flow reactor volume and improve the biogas collection system. By July 8, 1982, all modifications were completed, and both digesters were returned to operation. The plug flow reactor volume was increased from 40 to 93.5 m^3 and a new biogas collection cover and cover anchoring system were in place. No changes were made to the interior of the digester, with the exception of the removal of the effluent baffle.

Following its renovation, a tracer study was conducted to verify that the plug flow digester was indeed operating as a plug flow reactor without short-circuiting. The study consisted of feeding a homogeneous mixture of clay (532 kg) and fresh dairy manure to the digester and measuring the quantity of clay, measured as increase in ash content, recovered in the digester effluent versus time. The clay (which had a measured fixed solids concentration of 100% on a dry weight basis) was fed to the digester on July 21, 1982; and the digester was fed daily thereafter. The quantity of clay recovered daily was determined by subtracting the quantity of fixed solids in the effluent of the digester from that of the influent. As shown in Table 3.4, the study continued for 38 days, during which time approximately 223 kg of the initial clay were recovered. The theoretical hydraulic retention time (determined as the number of days of influent manure required for the total influent volume to equal the reactor volume) was calculated to be 18 days, and the study was conducted over two consecutive HRT's.

The first day following the addition of the clay to the digester the fixed solids concentration in the digester effluent increased and each day thereafter continued to increase for twelve days (Figure 3.13). Thirteen days after the addition of the clay the effluent fixed solids concentration began to decrease until it was equal to the influent concentration 28 days after initial start-up. The actual HRT (assumed to be the number of days of operation between start-up and the maximum effluent fixed solids concentration) was 12 days with short-circuiting in evidence, while the theoretical HRT was 18 days.

Following the tracer study, the plug flow digester was operated until February of 1983 in parallel with the completely mixed digester. During this period, the plug flow digester was operated at

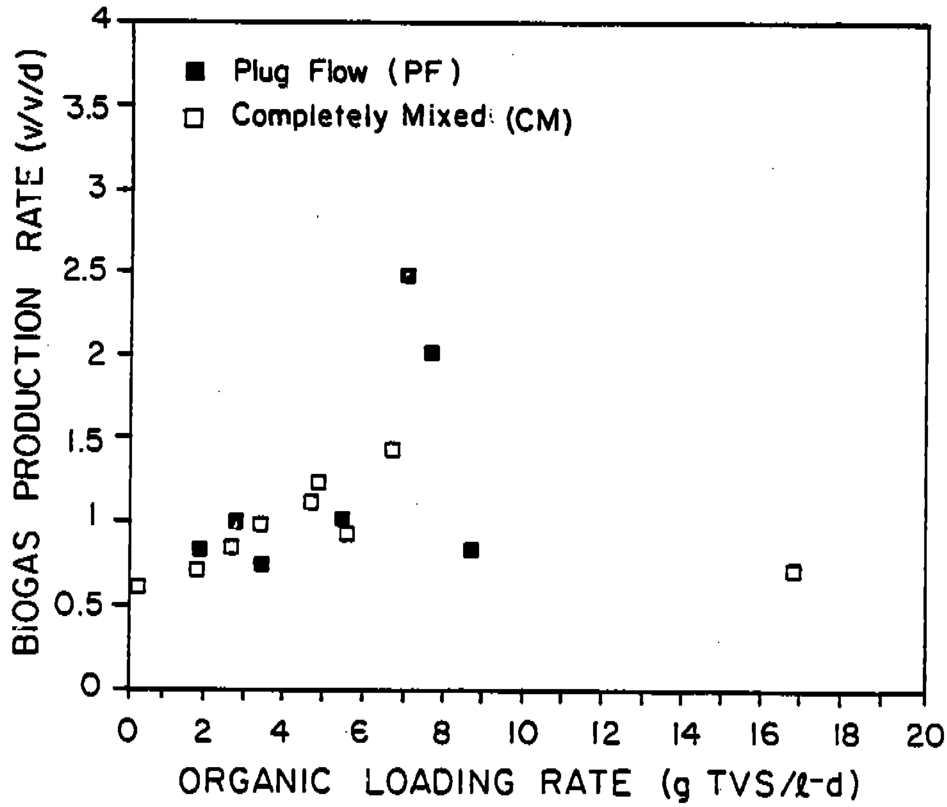


Figure 3.10. The rate of biogas production at 35°C versus the TVS organic loading rate.

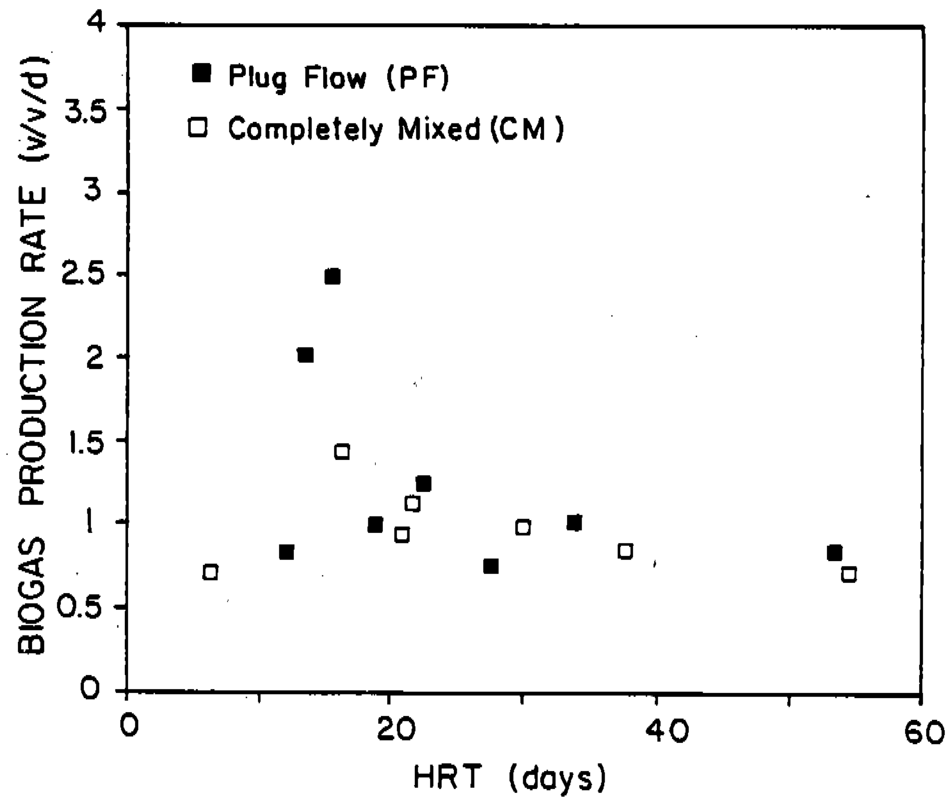


Figure 3.11. The effects of HRT on the rate of biogas production.

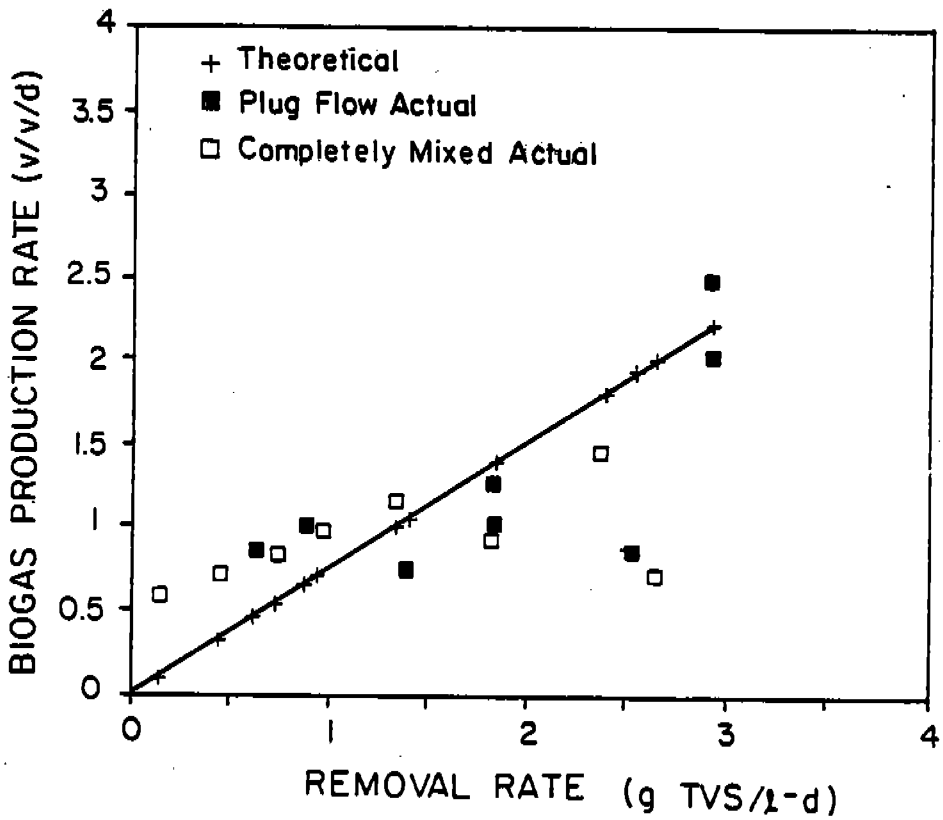


Figure 3.12. The relationship between actual and theoretical biogas production versus the rate of TVS removal.

TABLE 3.4. RESULTS OF THE CLAY TRACER STUDY CONDUCTED FOLLOWING THE RENOVATION OF THE PLUG FLOW DIGESTER

DATE	OPERATION TIME (days)	HRT (%)	FLOW RATE (m^3/day)	INFLUENT TS (%)	INFLUENT TVS (%)	EFFLUENT TS (%)	EFFLUENT TVS (%)	INFLUENT FS (kg/m^3)	EFFLUENT FS (kg/m^3)	CLAY RECOVERED (kg)
21 Jul 82	0	8.1	7.6	10.6	87.4	8.5	84.4	13.4	13.3	-0.7
22 Jul 82	1	11.4	3.1	10.6	87.4	8.6	84.4	13.4	13.4	-0.5
23 Jul 82	2	14.3	2.7	10.6	87.4	8.9	83.7	13.4	14.5	2.6
24 Jul 82	3	19.3	4.6	10.6	87.4	8.4	82.9	13.4	14.4	7.2
25 Jul 82	4	24.0	4.4	10.6	87.4	8.8	83.4	13.4	14.6	12.7
26 Jul 82	5	30.9	6.5	10.6	87.4	8.9	83.4	13.4	14.8	21.9
27 Jul 82	6	32.2	1.2	10.6	87.4	8.6	82.6	13.4	15.0	23.9
28 Jul 82	7	36.5	4.0	10.6	87.4	8.4	82.4	13.4	14.8	29.6
29 Jul 82	8	42.1	5.3	10.5	87.0	8.8	82.8	13.7	15.1	37.4
30 Jul 82	9	47.1	4.6	10.9	87.8	8.9	83.2	13.3	15.0	45.1
31 Jul 82	10	53.0	5.6	10.9	87.8	8.5	82.0	13.3	15.3	56.3
01 Aug 82	11	58.8	5.4	10.9	87.8	8.6	82.0	13.3	15.5	68.0
02 Aug 82	12	64.7	5.5	11.4	87.9	8.8	82.2	13.8	15.7	78.3
03 Aug 82	13	70.3	5.2	11.4	87.9	9.1	83.8	13.8	14.7	83.3
04 Aug 82	14	77.2	6.5	11.4	87.9	8.8	82.9	13.8	15.0	91.4
05 Aug 82	15	82.4	4.8	11.4	87.9	8.7	83.2	13.8	14.6	95.4
06 Aug 82	16	88.3	5.6	11.1	87.1	8.9	83.5	12.1	14.7	109.8
07 Aug 82	17	94.8	6.0	11.1	87.1	9.0	83.3	12.1	15.0	127.4
08 Aug 82	18	99.5	4.4	11.1	87.1	9.1	84.2	12.1	14.4	137.5
09 Aug 82	19	105.1	5.3	11.1	87.1	8.8	84.3	12.1	13.8	146.6
10 Aug 82	20	110.8	5.3	11.1	87.1	8.6	84.1	12.1	13.7	154.9
11 Aug 82	21	115.6	4.5	11.6	87.4	9.0	84.4	12.3	14.0	162.7
12 Aug 82	22	120.9	4.9	11.6	87.4	8.8	84.6	12.3	13.6	168.9
13 Aug 82	23	126.8	5.6	10.8	87.1	9.2	83.4	12.9	15.3	182.5
14 Aug 82	24	132.5	5.3	10.8	87.1	9.0	84.7	12.9	13.8	187.3
15 Aug 82	25	138.2	5.3	10.8	87.1	9.0	84.5	12.9	14.0	193.1
16 Aug 82	26	143.7	5.2	11.3	88.8	9.0	84.5	12.7	14.0	199.9
17 Aug 82	27	148.6	4.5	11.3	88.8	8.8	84.5	12.7	13.6	204.3
18 Aug 82	28	152.7	3.9	11.7	88.8	9.0	85.0	13.2	13.5	205.4
19 Aug 82	29	157.1	4.1	11.7	90.3	8.5	84.1	13.2	13.5	206.6
20 Aug 82	30	160.1	2.8	12.3	90.3	9.1	85.6	13.8	13.1	204.7
21 Aug 82	31	164.2	3.8	12.3	90.3	9.3	85.4	13.8	13.6	204.0
22 Aug 82	32	168.2	3.8	12.3	90.3	9.3	86.0	13.8	13.0	201.1
23 Aug 82	33	172.8	4.3	12.7	90.3	8.8	84.7	12.3	13.5	206.0
24 Aug 82	34	178.0	4.8	12.7	90.3	8.9	84.8	12.3	13.5	211.8
25 Aug 82	35	183.1	4.8	12.7	90.3	8.8	84.7	12.3	13.5	217.3
26 Aug 82	36	186.7	3.4	12.7	90.3	9.2	84.9	12.3	13.9	222.7
27 Aug 82	37	186.7	0.0	12.7	90.3			12.3	0.0	222.7
28 Aug 82	38	193.6	6.4	12.0	89.7	9.1	86.4	12.4	12.4	222.8

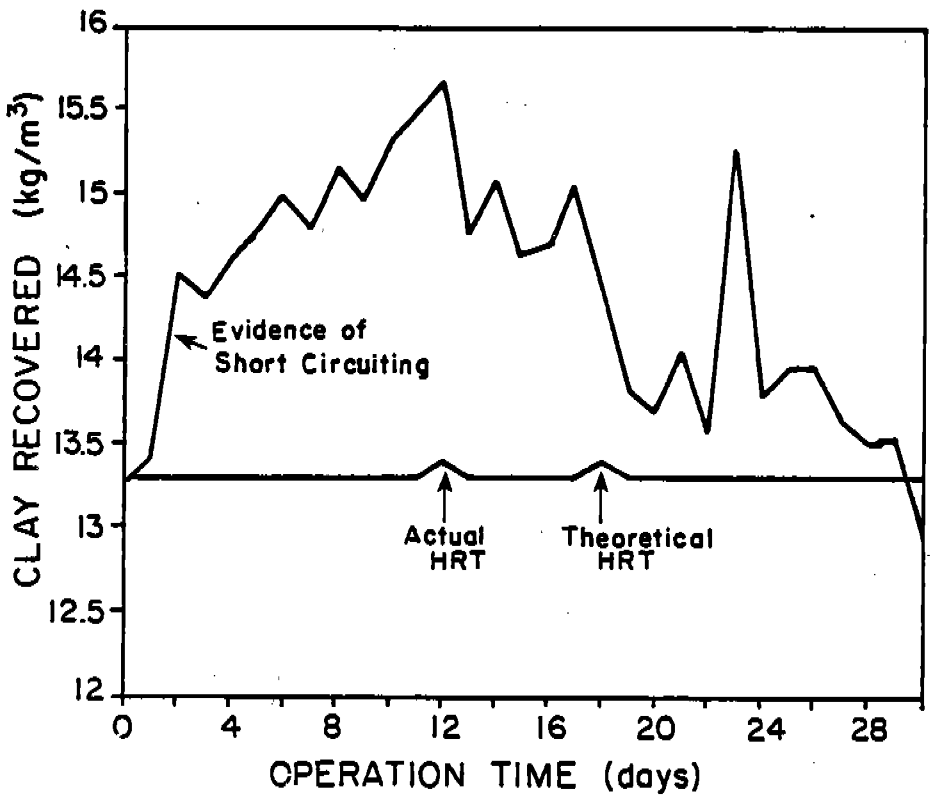


Figure 3.13. Daily quantities of clay recovered in the effluent of the remodeled plug flow digester during the tracer study.

organic loading rates from 2.8 to 8.5 g TVS/ℓ-d, as shown in Table 3.5. The rates and efficiencies of TVS removal were significantly less than those before the remodeling (Figure 3.13). The biogas production rate was consistent with the rate of TVS destruction as indicated by the similarity of the curves presented in Figures 3.14 and 3.15. However, as indicated by the ratio of biogas production to TVS destruction, there was slightly more biogas produced than was theoretically possible (greater than 0.76 liters of biogas per gram of TVS destroyed).

It is important to note that the only real difference between the conditions inside the reactor before and after the renovations was the removal of the effluent baffle, which was apparently responsible for eliminating short-circuiting. It was also during this period that bedding addition to the manure in the form of saw dust and wood shavings became the practice of operation at the facility and also the period in which the dairy manure for digestion was being gathered from dry cows and not those in lactation. These conditions continued until the end of the study.

III.B.4. Series Operation

From the middle of February 1983 until the termination of digester operation on June 14, 1983, the completely mixed and plug flow digesters were operated in series. This was done in an attempt to produce more biogas for use in cogeneration as well as to test an interesting design alternative. Feed manure from the storage tank was fed to the completely mixed reactor, and the effluent from that was fed to the plug flow unit. The average feed manure flow rate during this period was 6.3 m^3 per day, which produced an HRT of 5.5 days in the completely mixed reactor and a 20.5-day HRT through the entire system. It was not possible to maintain thermophilic temperatures in the completely mixed unit in this short retention time. Nearly 170 cubic meters of biogas were produced by the system daily. Biogas production from the completely mixed reactor was minimal at 10 cubic meters per day, and the biogas produced from this reactor did not have a measurable methane content. The temperature of this first reactor was only several degrees above ambient. The major portion of the biogas production and all of the methane production originated from the plug flow reactor. For this reason the biogas production rate was expressed in terms of the plug flow reactor volume and was calculated to be 1.8 v/v/d. As shown in Table 3.6, which summarizes the results of operation, the organic loading rate on the system was 5.2 g TVS/ℓ-d; and nearly 40% of the initial TVS entering the system was removed at the rate of 2.1 g TVS/ℓ-d (again expressed in terms of the plug flow reactor volume).

As shown in Figure 3.14, the series system performance results were similar to those of the plug flow reactor before the renovations were made. The completely mixed reactor became a preheat and mixing tank with a retention time over five days. It effectively pretreated the manure and significantly improved the performance of the plug flow digester. Data accumulated during this period of series operation are presented in Appendix D.

TABLE 3.5. SUMMARY OF RESULTS OF OPERATION OF THE PLUG FLOW DIGESTER AT A REACTOR VOLUME OF 93.5 m^3

DATE	FLOW RATE (ℓ/d/1000)	----INFLUENT---- TS (%)	VS (%)	pH	----EFFLUENT---- TS (%)	VS (%)	pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S R E M O V A L RATE (g/ℓ/d)	EFFICICIENCY (%)	GAS/TVS (ℓ/g)
15-Jul-82	5.6	10.8	87.4	6.7	9.2	85.4	7.7	16.7	1.77	5.65	0.95	16.76	1.87
04-Sep-82	2.3	12.7	89.5	6.5	9.4	85.6	7.6	40.7	0.93	2.80	0.82	29.21	1.14
18-Sep-82	3.6	11.2	89.3	6.5	10.1	86.3	7.5	26.0	1.22	3.85	0.49	12.85	2.47
25-Sep-82	4.1	11.2	88.8	6.5	9.5	85.9	7.6	22.8	1.40	4.36	0.78	17.95	1.78
02-Oct-82	5.8	10.8	88.5	6.5	9.0	86.0	7.6	16.1	1.65	5.93	1.13	19.02	1.47
13-Oct-82	4.9	12.5	89.3	6.4	9.0	86.4	7.6	19.1	1.84	5.85	1.77	30.34	1.04
14-Nov-82	3.5	11.3	87.6	6.8	8.5	85.8	7.7	26.7	1.09	3.71	0.98	26.32	1.12
21-Nov-82	5.1	11.8	88.3	6.9	8.4	83.9	7.9	18.3	1.19	5.68	1.84	32.36	0.65
28-Nov-82	3.7	12.3	87.9	6.8	8.7	84.9	7.7	25.3	0.96	4.28	1.36	31.68	0.70
05-Dec-82	3.9	10.8	87.3	7.2	9.1	85.3	7.9	24.0	1.21	3.93	0.69	17.67	1.74
12-Dec-82	4.0	10.6	87.1	7.0	8.9	84.2	7.5	23.4	1.11	3.95	0.74	18.83	1.49
19-Dec-82	5.0	12.7	87.7	7.0	9.6	85.0	7.8	18.7	1.37	5.96	1.59	26.74	0.86
26-Dec-82	6.0	10.6	87.2	6.8	9.1	84.5	7.8	15.6	1.31	5.93	1.00	16.81	1.31
02-Jan-83	7.4	11.0	87.4	6.8	9.3	84.8	7.8	12.6	1.52	7.61	1.37	17.97	1.11
09-Jan-83	7.8	11.6	87.9	6.8	9.4	85.2	7.7	12.0	1.50	8.51	1.82	21.45	0.82
16-Jan-83	5.3	12.4	89.2	6.9	9.6	85.7	7.7	17.6	1.45	6.27	1.61	25.62	0.90
23-Jan-83	5.6	11.9	88.9	7.2	9.4	86.1	7.7	16.7	1.53	6.34	1.49	23.50	1.03
06-Feb-83	4.7	12.2	88.6	6.9	9.6	84.8	7.8	19.9	1.45	5.43	1.34	24.69	1.08

*Reactor Volume = 93.5 m^3

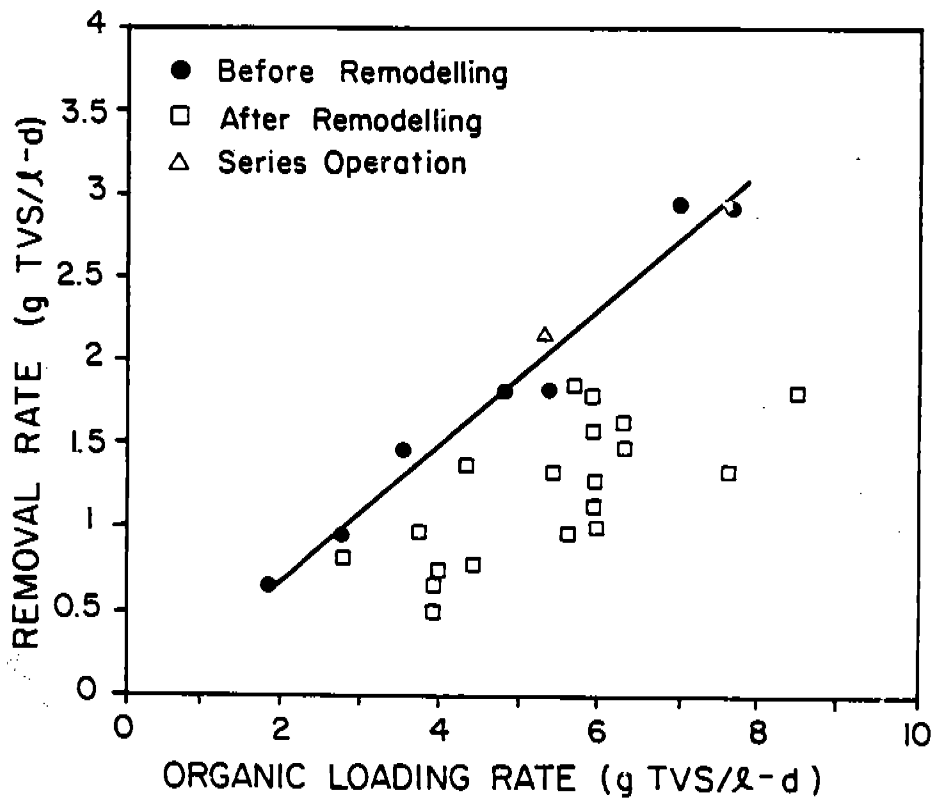


Figure 3.14. The relationship of the TVS removal rate to the organic loading rate before and after renovation of the plug flow digester.

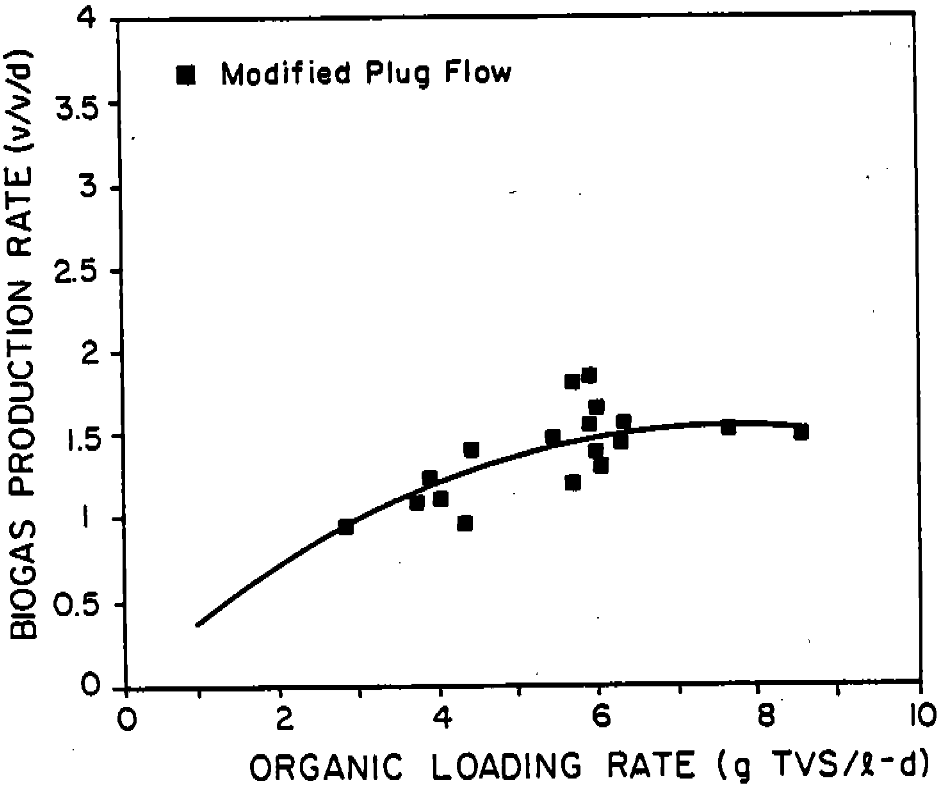


Figure 3.15. The relationship between biogas production and organic loading rate after renovation of the plug flow digester.

TABLE 3.6. SUMMARY OF RESULTS OF OPERATION OF THE FULL SCALE DIGESTERS IN SERIES

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	pH	COMPLETE MIXED DIG EFFLUENT TS (%)	COMPLETE MIXED DIG EFFLUENT VS (%)	COMPLETE MIXED DIG pH	PLUG FLOW DIGESTER EFFLUENT TS (%)	PLUG FLOW DIGESTER EFFLUENT VS (%)	PLUG FLOW DIGESTER pH	HRT (days)	BIOGAS (v/v/d)	LOADING (g/ℓ/d)	T V S RATE (g/ℓ/d)	R E M O V A L EFFICICIENCY (%)	GAS/TVS (ℓ/g)
20-Feb-83	6.7	12.0	87.5	6.9	9.6	85.3	7.6	9.4	85.1	7.7	19.2	1.71	5.46	1.79	32.83	0.95
06-Mar-83	6.7	11.6	87.2	7.3	10.7	87.0	7.0	8.8	84.1	7.7	19.2	1.68	5.26	1.95	36.99	0.86
20-Mar-83	6.6	13.0	88.6	7.0	11.2	87.0	7.0	9.1	84.4	7.8	19.5	2.03	5.90	2.71	45.93	0.75
27-Mar-83	6.2	12.4	87.7	6.8	11.1	87.2	6.9	9.0	84.3	7.8	20.8	1.94	5.23	2.18	41.68	0.89
03-Apr-83	5.3	12.2	88.0	7.1	11.4	87.3	6.9	8.9	84.6	7.9	24.3	1.48	4.41	1.82	41.18	0.82
Average	6.3	12.2	87.8	7 0	10.8	86.8	7 1	9.0	84.5	7.8	20.5	1.77	5.25	2.09	39.7	0.85

III.B.5. Component Reliability

The results presented in this section are subjective observations on the performance of the individual components of the biogas production, handling, and storage systems. The two digesters were designed as short-term research vessels, yet operation continued without significant interruption for over five years. During this period surprisingly few problems were encountered, though several minor modifications were made to each reactor.

Though the expansion and renovation successfully solved the problems associated with biogas collection, it opened the question of manure short-circuiting in the digester. The removal of the effluent baffle during the renovation process apparently increased the possibilities of short-circuiting. This baffle was a minor cost in the system but may be a critical component in preventing short-circuiting problems.

Another method of minimizing short-circuiting in the digester was determined during the period of series operation. The use of the completely mixed reactor as the preconditioning tank prepared the manure for the plug flow digester supplying heat and initial anaerobic degradation. Short-circuiting was not evident during the period of series operation.

Over the five years of digester operation the biogas produced from the digesters was conveyed to points of use with metal piping. The interiors of these pipes accumulated thick, black deposits of sludge. These deposits were noticed wherever the biogas came in contact with metal. Though there did not appear to be serious harm to the piping, the deposits were often transported to places where harm could be done, such as at the compressors, storage vessels, and particularly in the cogeneration equipment.

Two forms of biogas storage containers were tested in this study, a flexible low pressure tank (less than 5 cm of water column) with a volume of 38 m^3, and two medium pressure storage tanks (maximum 250 psi) having a total volume of 14 m^3. The pillow tank proved to be an important component of the biogas handling system. It provided a constant low back pressure (0.5 to 1.0 cm of water column) on the digester system, which maintained inflation of the biogas collection covers throughout the periods the pillow tank itself was being filled and emptied. Taking advantage of its physical movement during inflation and deflation, a mechanical means of controlling the cycling of the compressors was possible. When the pillow tank was sufficiently filled it would physically trip a switch which would engage the compressors and likewise protect the digesters from implosion by disengaging the compressors at the appropriate time of deflation.

The medium pressure tanks were used to store the biogas produced overnight for use during the next day. These tanks were used propane tanks and could maintain pressures up to 250 psi; however, they did not represent a very large storage capacity. The maximum volume of biogas which these tanks could store represented approximately one day's production from the digester system. Accumulations of sludge in these tanks were evident also especially when accumulated condensate was evacuated.

Another component necessary with medium pressure storage was the compressor. A two-stage piston compressor was used in this study and was frequently a source of problems throughout the study. Raw biogas containing methane, carbon dioxide, water vapor, trace concentrations of sulfur, as well as other trace components, was not easily processed by this type of compressor. The major source of problems in the area of biogas handling was associated with medium pressure compression and storage. It was also the most expensive and least cost-effective.

Another compressor used in the study was a small rotary vane type. The main function of this compressor was to supply biogas to the cogenerator; however, it proved to be reliable for all functions associated with moving biogas. The maximum pressure developed by the compressor was 3 psi, and this proved adequate for most biogas handling functions.

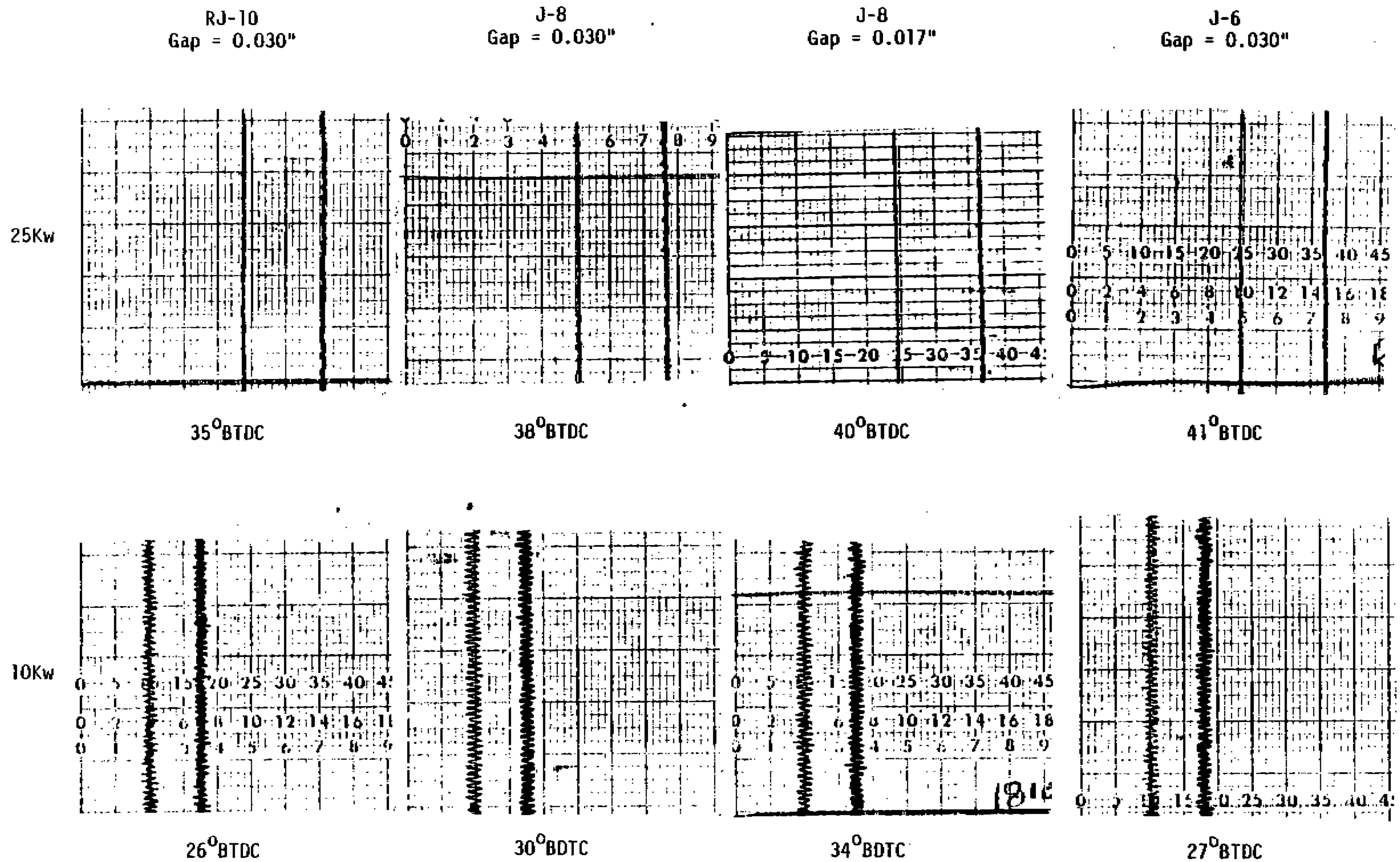
III.C. RESULTS OF COGENERATION PERFORMANCE STUDIES

III.C.1. Short-term Performance Tests

The performance studies of the cogenerator were designed to collect information on three primary topics. They were: (1) to define critical spark system parameters; (2) to describe the characteristics of the induction generator; and (3) to determine the energy recovery performance of the cogenerator. The original data from which the results were extrapolated are summarized in Appendix I.

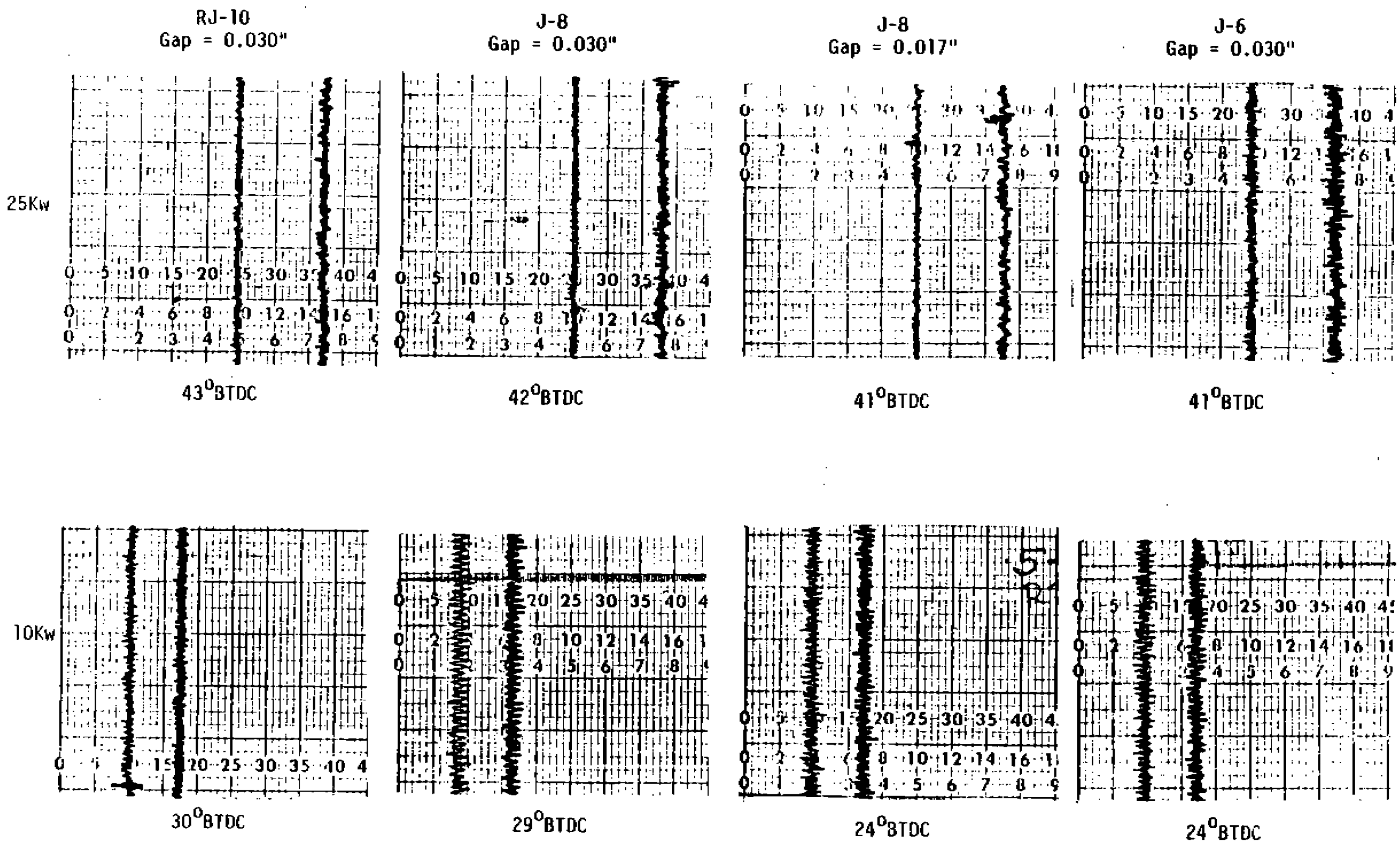
During the initial start-up of the cogenerator, rough running and misfiring proved to be problems. Better gas pressure regulation and modifications to the carburetor eliminated most, but not all, of the problem. The spark system was identified as the possible source of the remaining problems. Thus our initial testing was designed to check spark plug gap, spark plug heat range, and spark timing for their effect upon rough engine operation. The strip chart recording of electrical output from the generator was used as an indicator of smooth or rough operation of the engine. The degree of the irregularity of the trace of electrical output provided an indirect indication of rough combustion of the biogas, and sudden spikes indicated misfiring.

Three spark plugs with different heat ranges (Champion J-6, J-8, and RJ-10) were checked at loads of 10 and 25 kW and at a lean and rich fuel air mixture (Figures 3.16 and 3.17). Spark timing was set at the most retarded level at which peak power would be produced. At lean fuel-air mixtures, there was no apparent advantage of one spark plug over another. However, at rich mixtures the hotter plug (RJ-10) provided slightly smoother operation at both loads. Spark plug gap was also checked under similar conditions to plug heat



Left line indicates kilowatt output and right line indicates kilovolt-amp output from generator.

Figure 3.16. Effect of spark plug selection and gap on smoothness of engine operation under lean fuel-air mixtures (equivalence ratio = 0.92).



Left line represents kilowatt output and right line indicates kilovolt-amp output from generator

Figure 3.17. Effect of spark plug selection and gap on smoothness of engine operation under rich fuel-air mixture (equivalence ratio = 1.25).

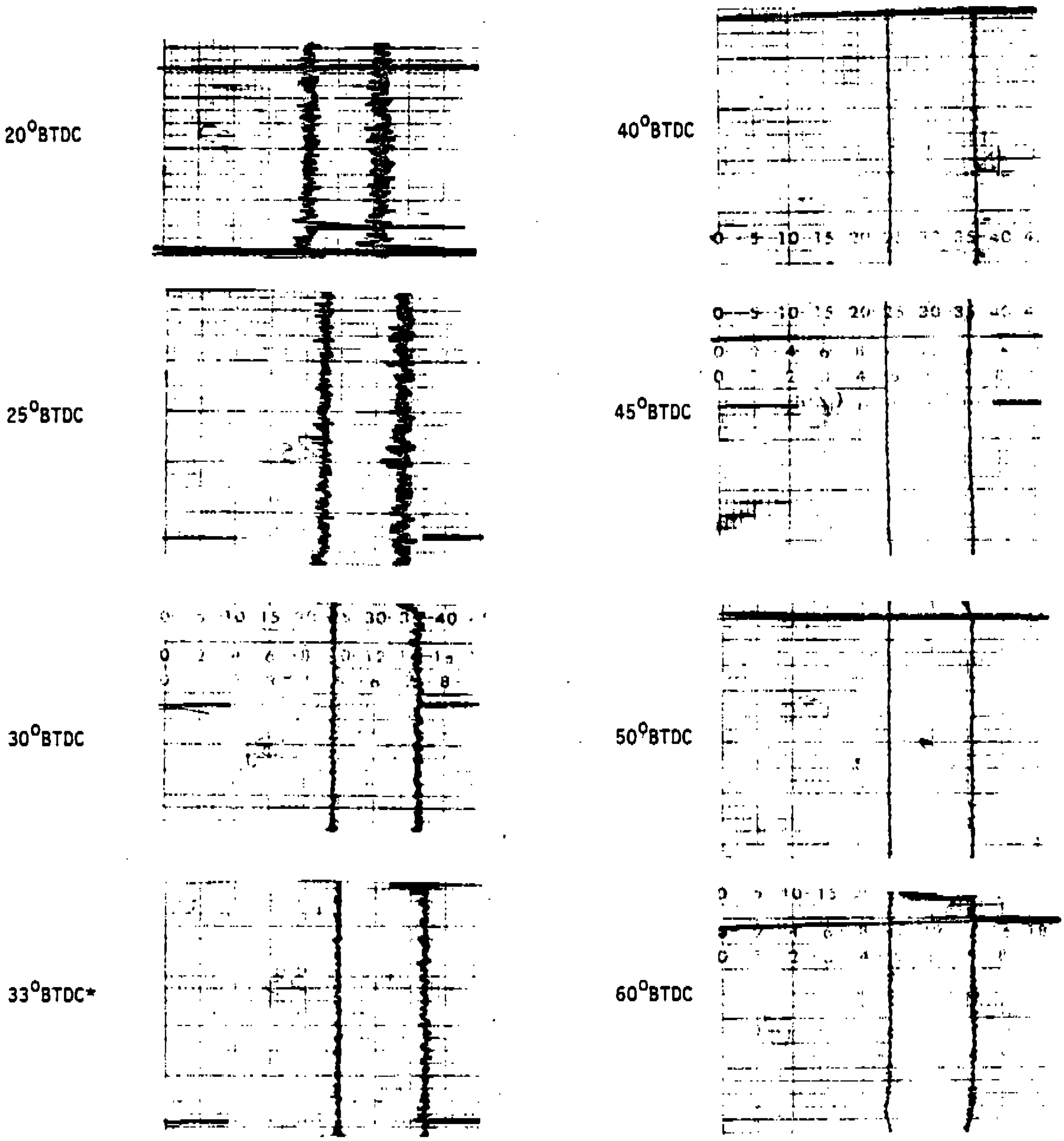
range. A gap of 0.043 cm and 0.076 cm (0.017 inch and 0.030 inch) was checked. No difference in engine operation was noted for the two spark plug gaps. Under all of the conditions described, misfiring was not noted.

Timing of the spark proved to be a more important parameter for maintaining smooth engine operation. The effect of spark timing is illustrated in Figure 3.18 for a lean fuel-air mixture and operation at rated load. A spark timing of less than 20 degrees before top dead center (BTDC) resulted in very rough operation and regular misfiring. At a spark timing of 20 and 25 degrees BTDC, rough operation was still noted, and an occasional muffled misfiring was observed. Retarding the timing to 33 degrees BTDC provided reasonably smooth operation and was the minimum level at which peak power was achieved. The smoothest operation was observed for a spark setting from 40 to 50 degrees BTDC. However, power output began to slowly diminish for a spark timing of 45 degrees BTDC or greater. The minimum spark timing for peak power output is illustrated in Figures 3.19 and 3.20 for a range of loads and a rich and lean fuel-air mixture. Minimum spark timing for maximum power varied from about 25 degrees BTDC at 5 kW to about 40 degrees BTDC at rated load for both the rich and lean fuel-air mixtures. An additional retarding of the spark by about 5 degrees provided the smoothest operation without a loss in power for all conditions checked. Spark timing was a critical factor for maintaining smooth engine operation.

Our next series of tests was designed to define some of the characteristics of the induction generator (Figures 3.21, 3.22, 3.23, and 3.24). The induction generator's power output varied with speed. No load occurred at the synchronous speed of the unit or 1800 RPM, and rated load of 25 kW was attained at 1837 RPM. At 25%, 50%, and 100% of rated load the corresponding generator slip was 0.25%, 0.60%, and 2.1%, respectively. Our data compared very closely with that reported by the generator manufacturer for generator slip.

The induction generator also exhibits some change in electrical output versus speed in the first hour of operation after start-up (Figure 3.22). With the engine speed set at 1825 RPM, the generator initially produced 24 to 25 kW. If the engine speed was held constant, the generator output slowly diminished over the next hour. The generator finally stabilized at an output of 20 kW.

The generator's power factor without capacitance correction proved far less than suggested by the manufacturer. A peak power factor of 66% lagging was noted at loads from 20 to 23 kW (Figure 3.23). Below 15 kW the power factor dropped very rapidly. The reactive power requirements of the generator were high, resulting in high current flow. For example, at rated load the generator required 29 kVAR's of reactive power, and the resulting line current was 160 amperes. A 15 kVA capacitor bank was later placed in parallel with the generator to correct the low power factor (Figure 3.24). At rated load the power factor was increased to 0.84 lagging. As a result, the electrical service to the generator only needed to provide approximately 16 kVAR's of reactive power, and the resulting



*Minimum spark advance for maximum power output.

Left line represents kilowatt output and right line indicates kilo-volt-amp output of generator.

Figure 3.18. Effect of spark timing on smoothness of engine operation (equivalence ratio = 0.92, load 25 kW).

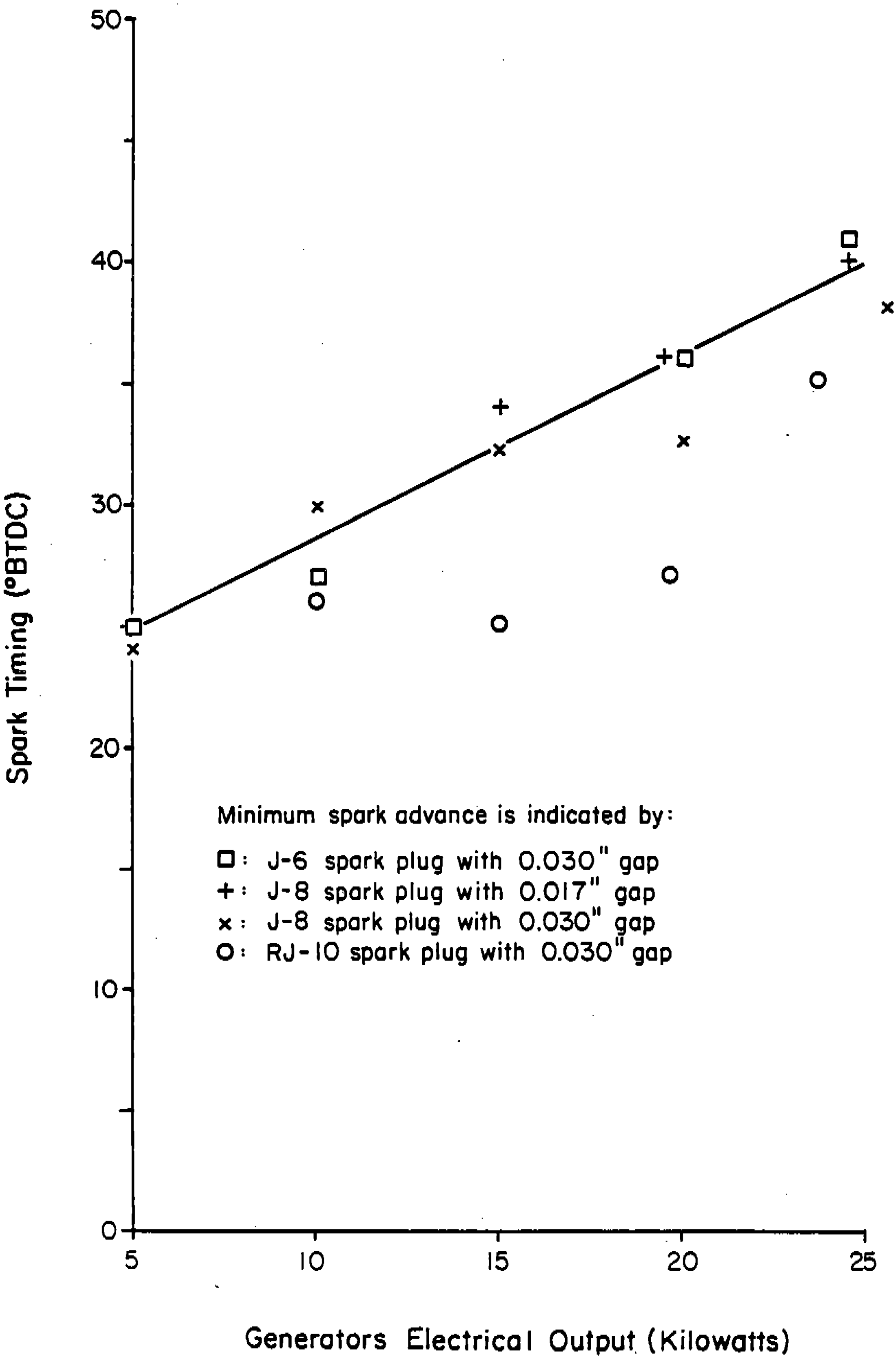


Figure 3.19. Minimum spark timing for maximum power loads for lean fuel-air mixtures (equivalence ratio = 0.92).

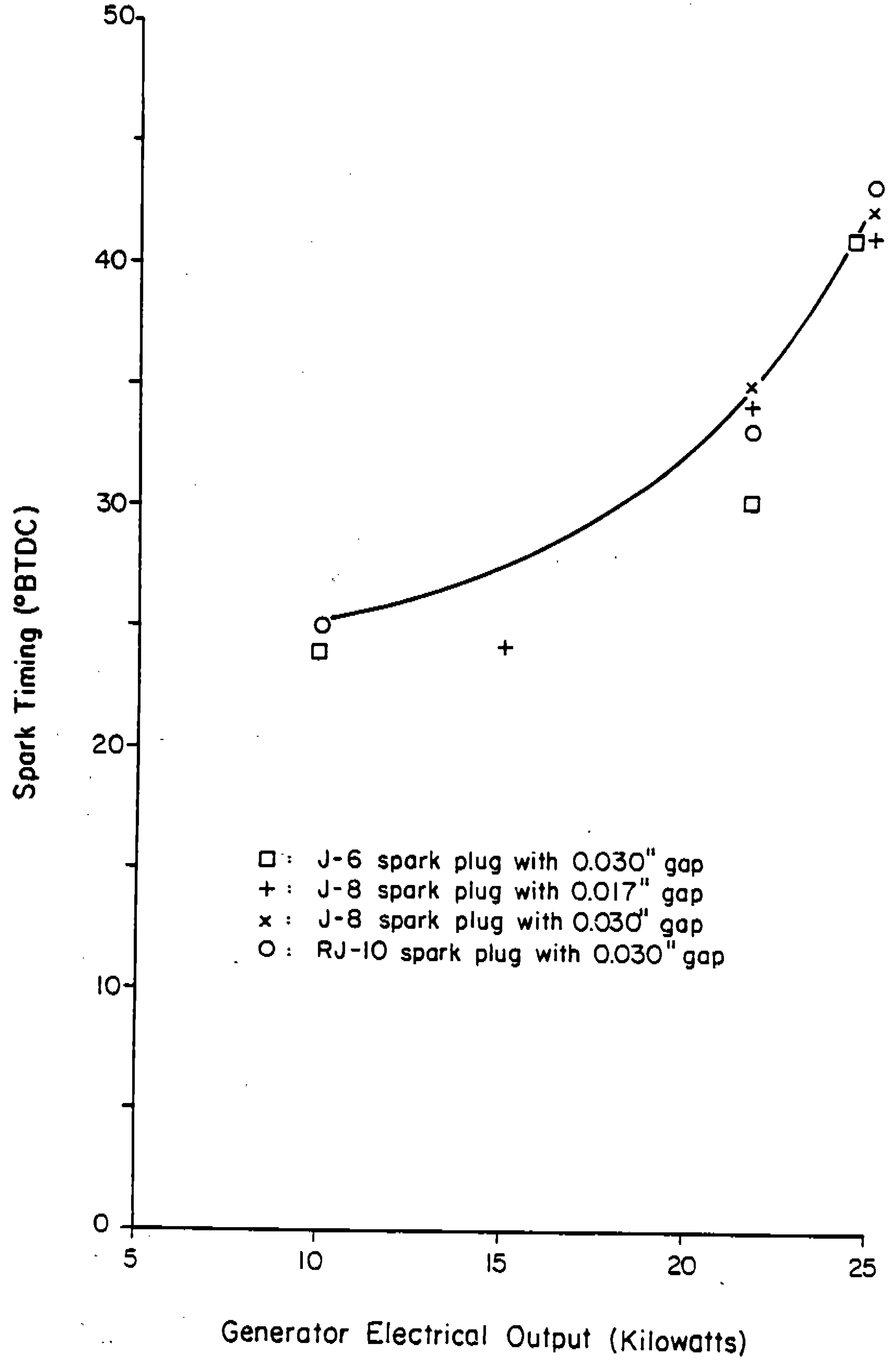


Figure 3.20. Minimum spark timing for maximum power at various loads for rich fuel-air mixtures (equivalence ratio = 1.25).

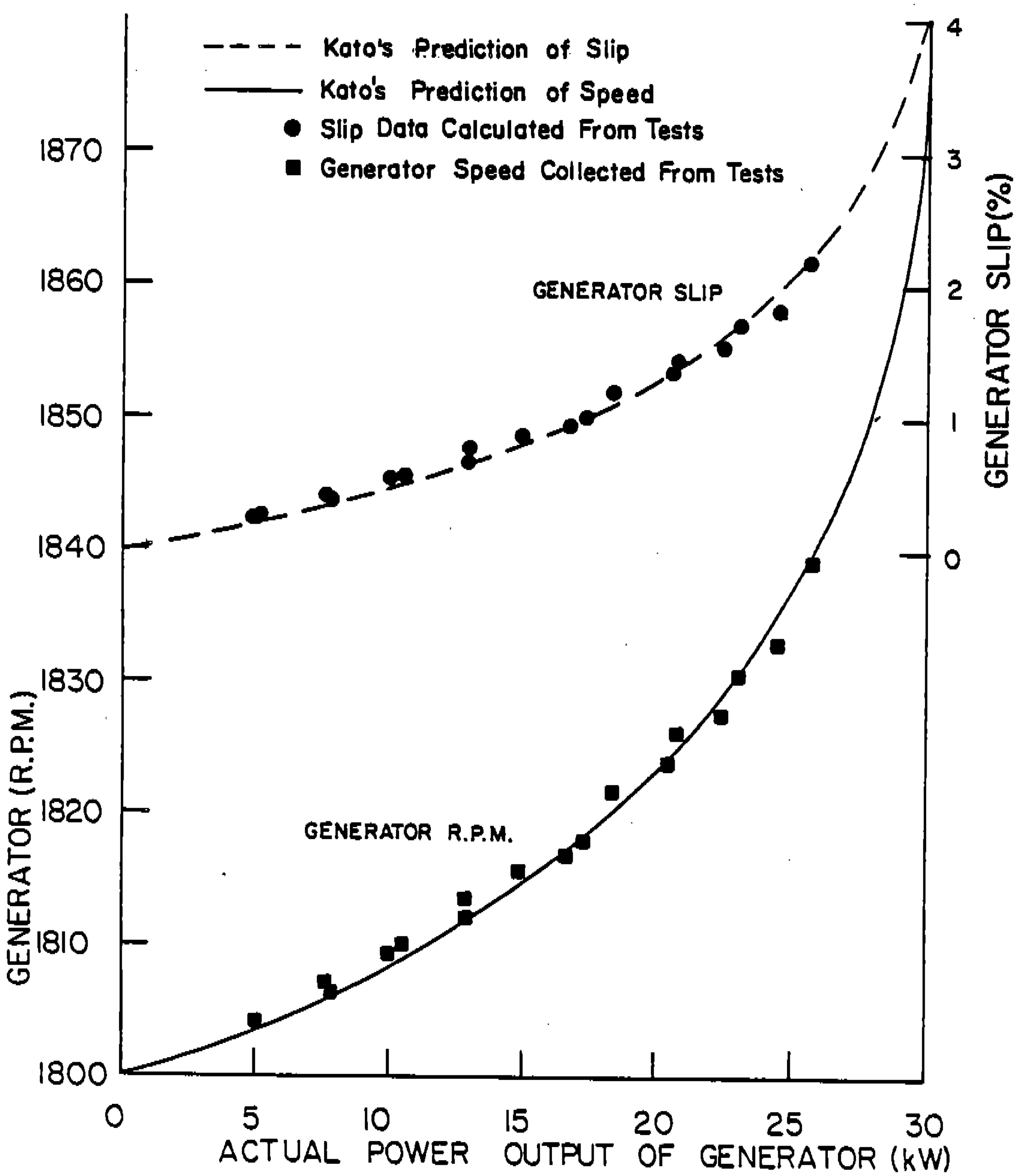


Figure 3.21. Generator speed and slip versus generation load as predicted by Kato and from performance tests.

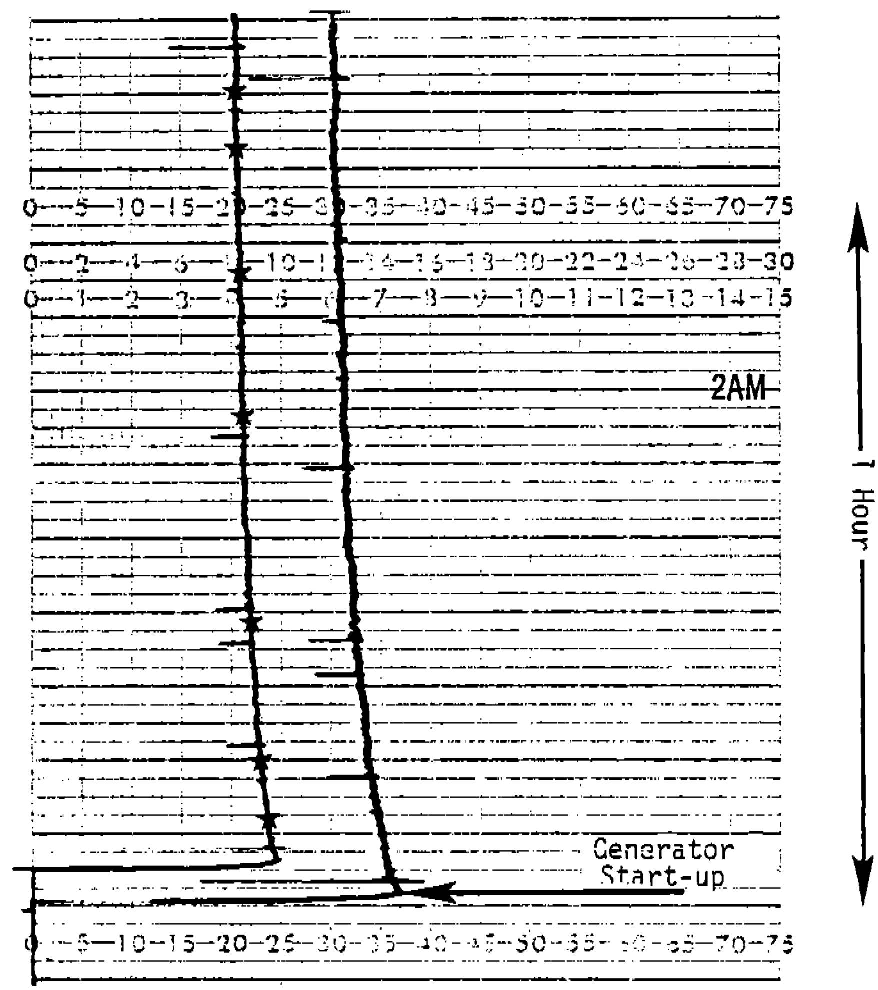


Figure 3.22. Electrical output of generator immediately after start-up.

(▬ = kilovolt amps
★ = kilowatts)

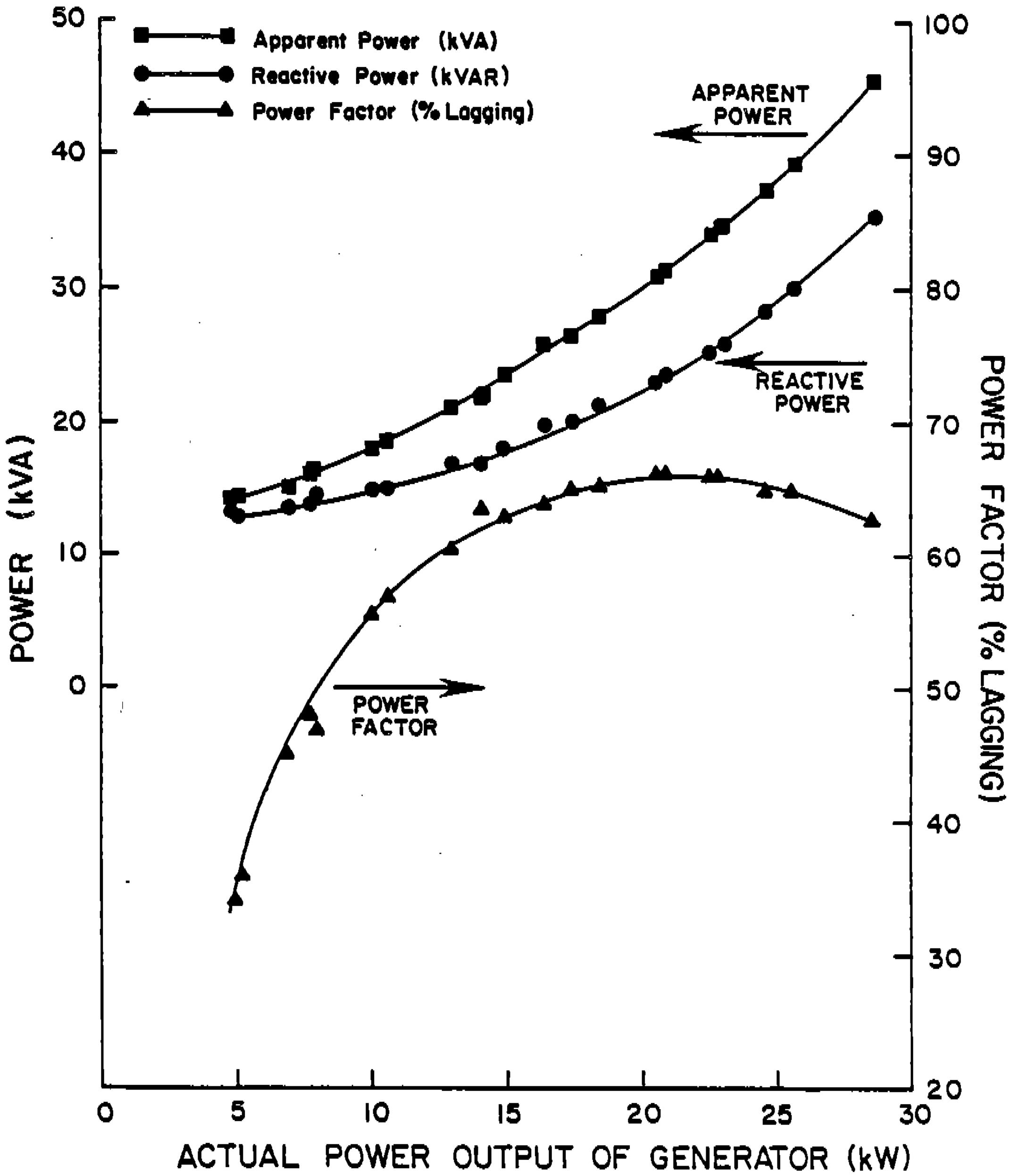


Figure 3.23. Apparent and reactive power and power factor versus generator actual power output (without capacitance correction).

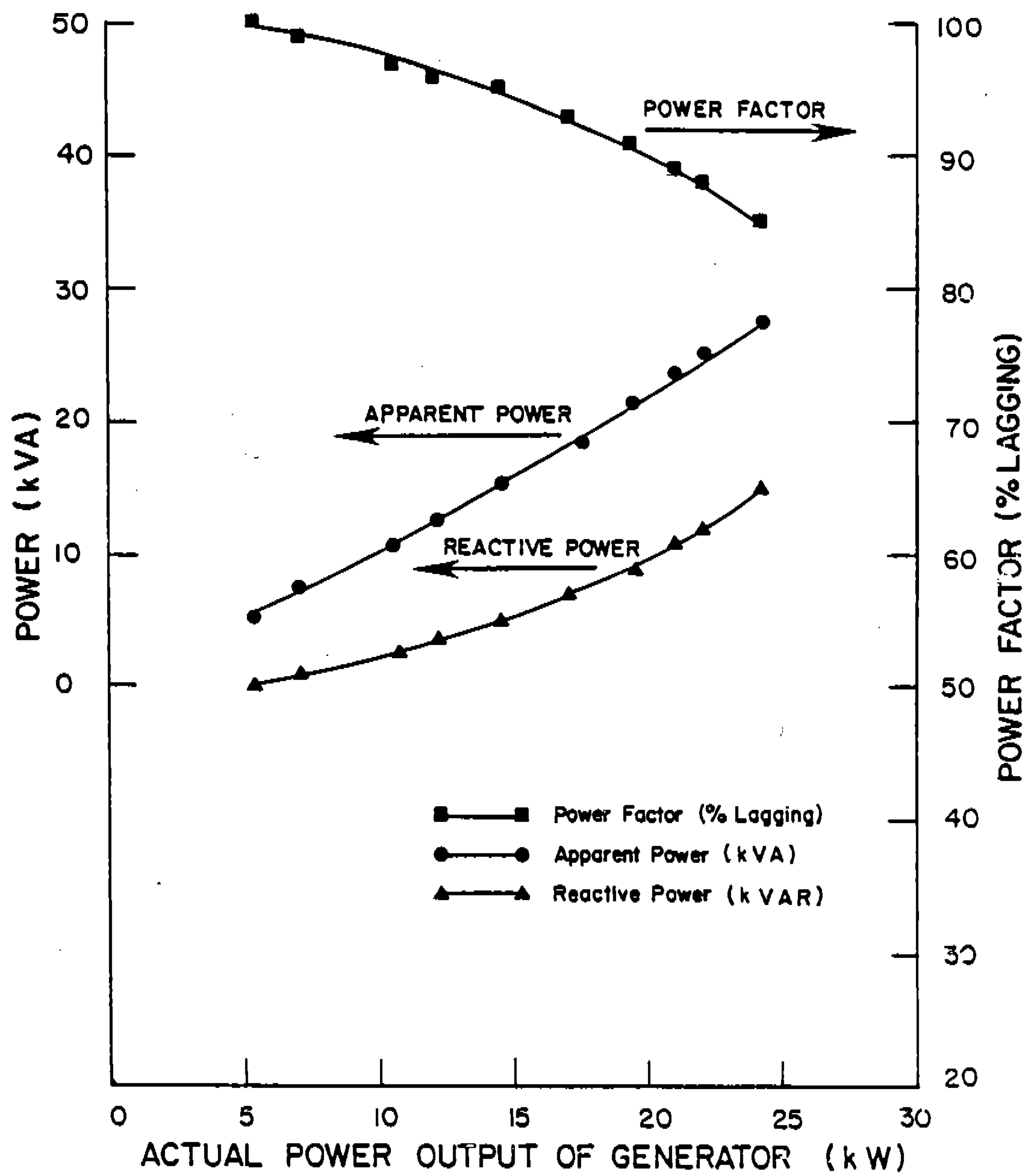


Figure 3.24. Apparent and reactive power and power factor versus generator actual power output (with capacitance correction).

line current had been reduced to 124 amperes. With the capacitance correction, even larger power factor improvements were noted for part load conditions. At a 5 kW load power factor reaches 100%. The 15 kVA capacitor bank reduced the reactive power requirement of the electrical service by 12 to 13 kVAR's, illustrating that it was performing near its rated potential.

The thermodynamic performance of the cogenerator is reported in Figures 3.25 through 3.31. The cogenerator's maximum power output of 28.5 kW was observed at a slightly rich fuel-air mixture (Figure 3.25). The rated power of the cogenerator, 25 kW, could be achieved for equivalence ratios ranging from 0.85 to 1.3. The equivalence ratio for this set of tests should only be considered an approximation. The current flow at peak power output often exceeded the current carrying capacity of our electrical service due to the low power factor of the generator. If this occurred, the peak power output would be determined in a relatively short period of time. The fuel-air mixture, which required several minutes to test, would then be checked after reducing the generator output to 150 amps (about 24 kW), a more reasonable level for the electrical service. Only a minor variation, if any at all, should have been noted in fuel-air mixtures under those two conditions.

The next series of tests was designed to document the thermal efficiency of the generator at rated load over a range of fuel-air mixtures (Figure 3.26). Checks of electrical efficiency revealed that it peaked at 26% between an equivalence ratio (Ø) of 0.8 and 0.9 for the range tested. The electrical efficiency dropped below 20% for equivalence ratios of 1.2 or richer. The thermal efficiency of the heat recovery system peaked between 42 and 45% for fuel-air mixtures leaner than Ø = 1.0. At Ø = 1.3 the heat recovery system was capturing less than 35% of the fuel's energy. Lean operation shows definite advantages in terms of the efficiency of energy recovery.

In addition, thermodynamic performance was checked over a range of loads from 5 to 25 kW for three carburetor settings (Ø equal to 0.85, 0.95, and 1.1). Again, the value of lean operation is illustrated (Figure 3.27, 3.28, 3.29). Electrical efficiency is consistently higher for the entire range of loads at Ø = 0.85. A considerable advantage was also observed for operation near rated load. At a 5 kW output, the electrical efficiency dropped to between 10 and 12%. The advantage of lean operation was also observed for heat recovery efficiency at loads approaching 25kW. This advantage for lean operation dissipates for light loads. Thermal efficiency for the heat recovery system also peaks at part loads in direct contrast to electrical efficiency. Thermal efficiency peaked at about 55% for an electrical output of 5 kW.

The total energy recovered as electrical or heat energy is illustrated in Figure 3.30. The total thermal efficiency of the cogenerator remains fairly constant with load and favors the leaner fuel air-mixtures. The value of operation at partly or fully loaded conditions may depend on whether the need for and value of electricity or hot water is greater.

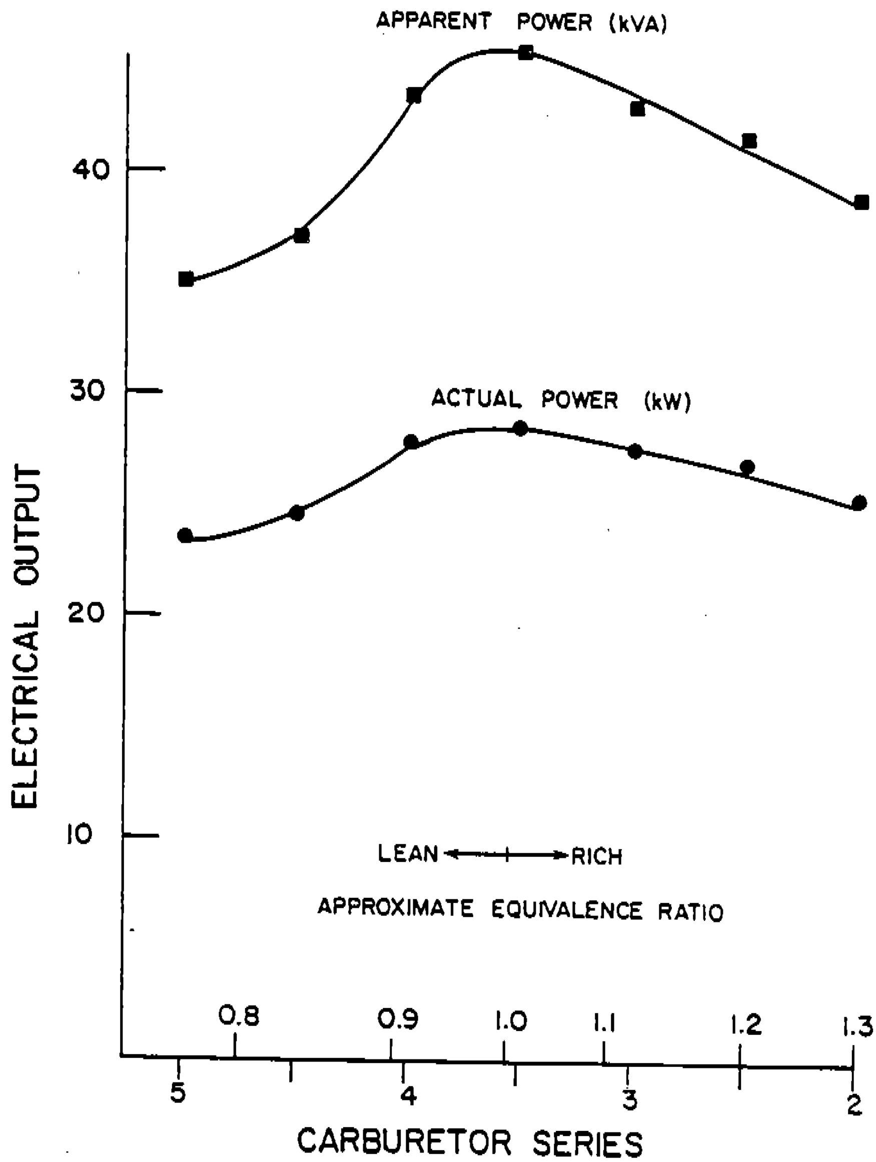


Figure 3.25. Maximum electrical output of cogenerator at various fuel-air mixtures.

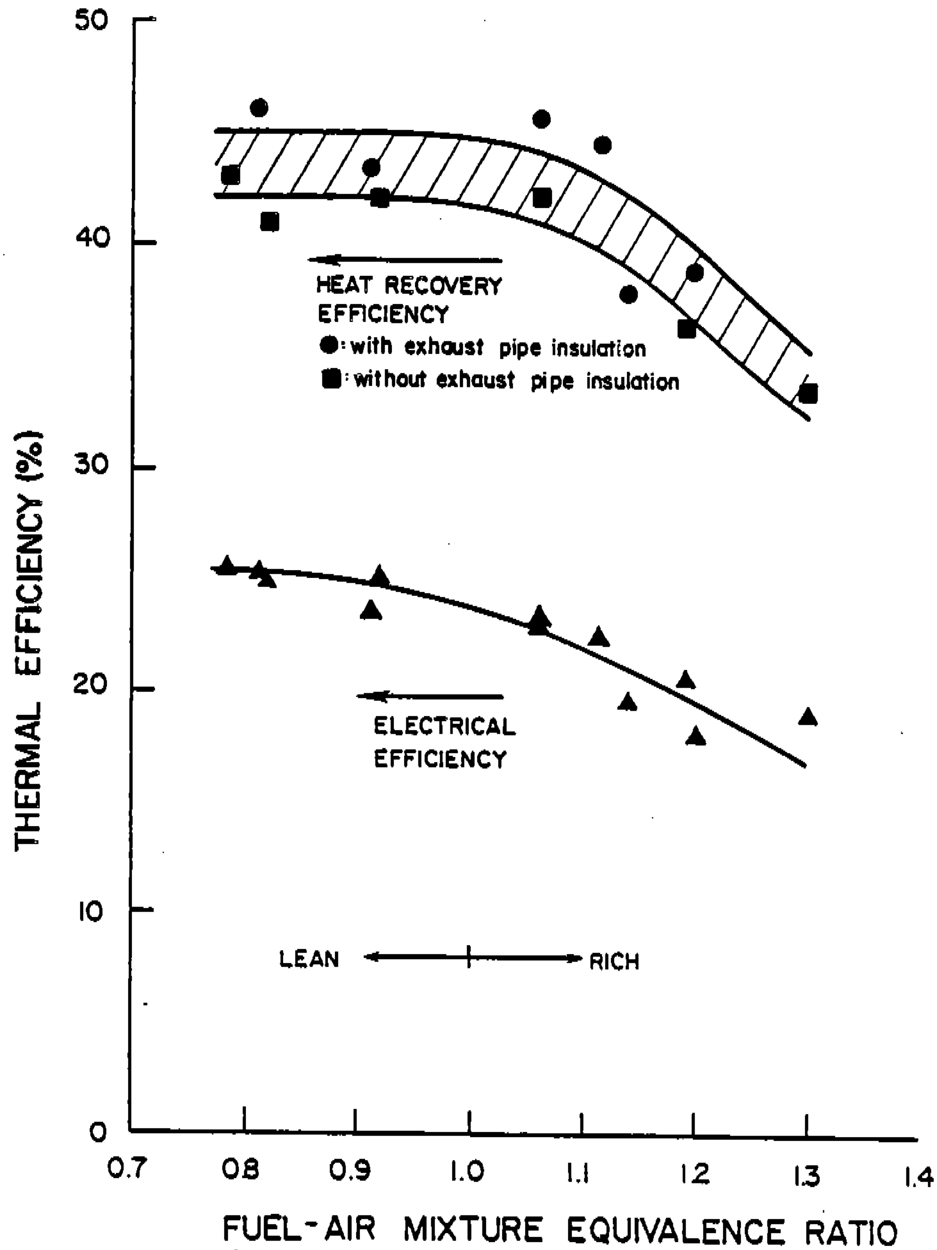


Figure 3.26. Thermal efficiency of cogenerator at rated power versus fuel-air mixture.

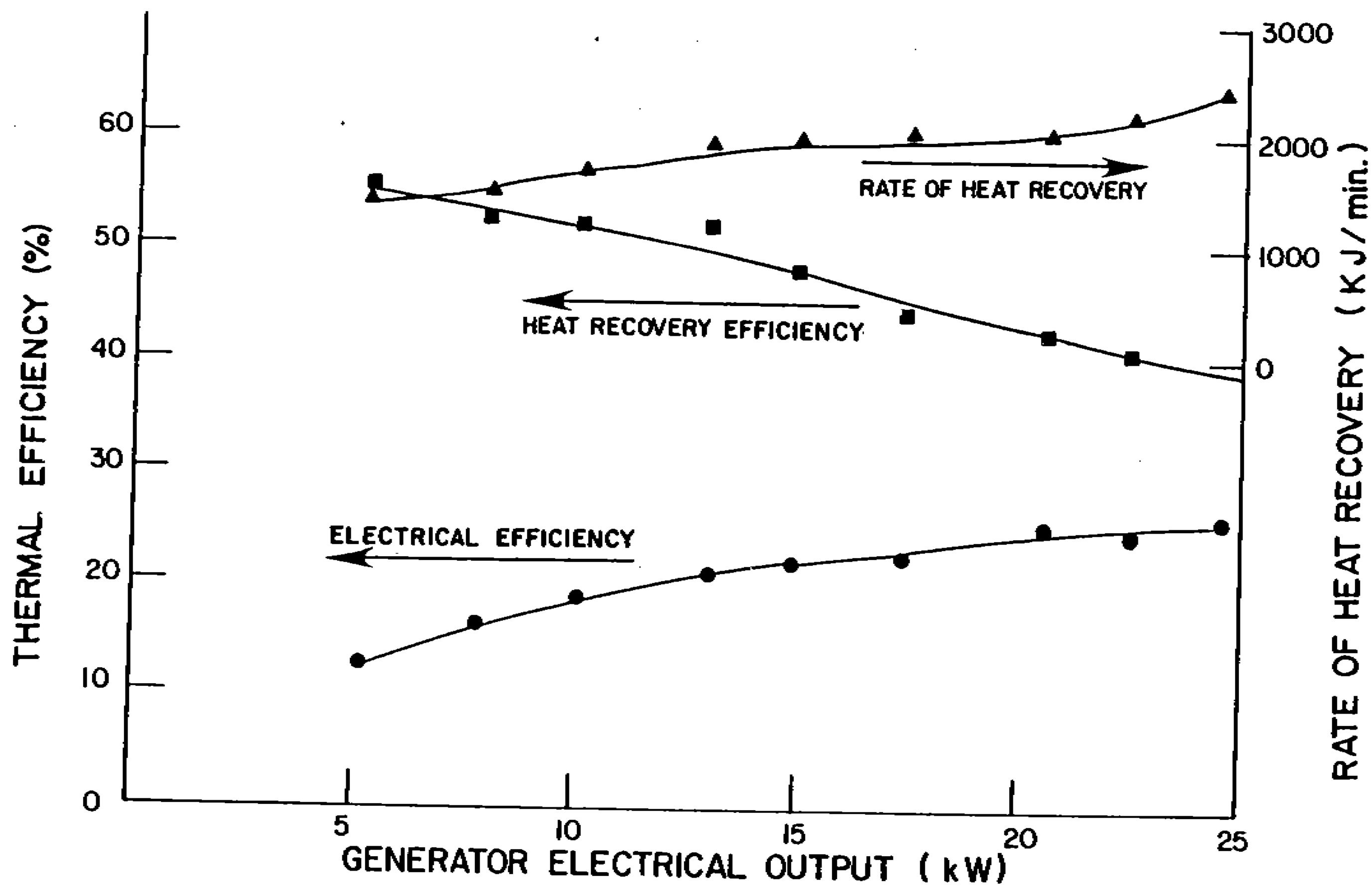


Figure 3.27. Performance of cogenerator at various loads ($\phi \cong 0.85$).

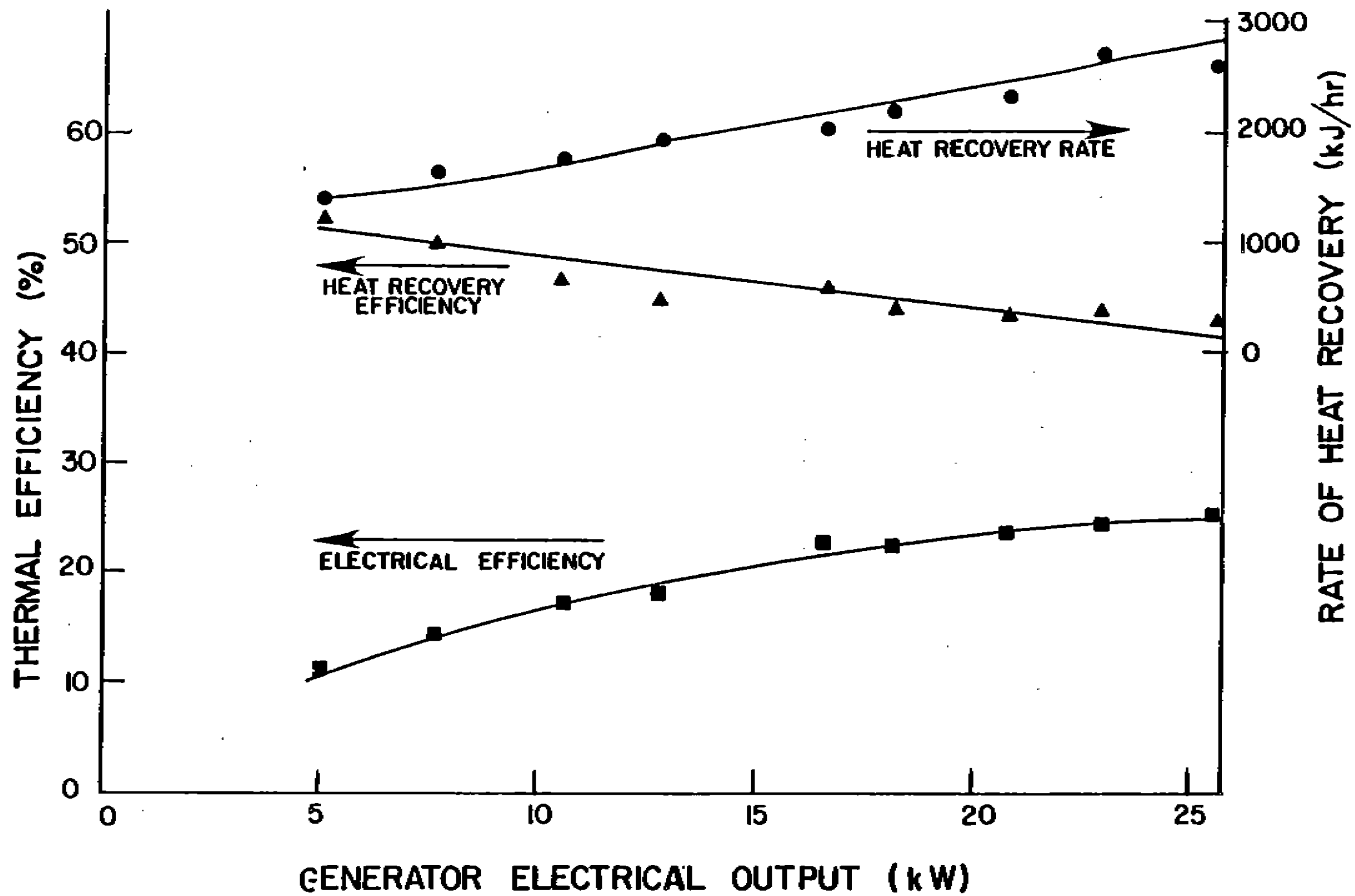


Figure 3.28. Performance of cogenerator at various loads ($\phi \cong 0.95$).

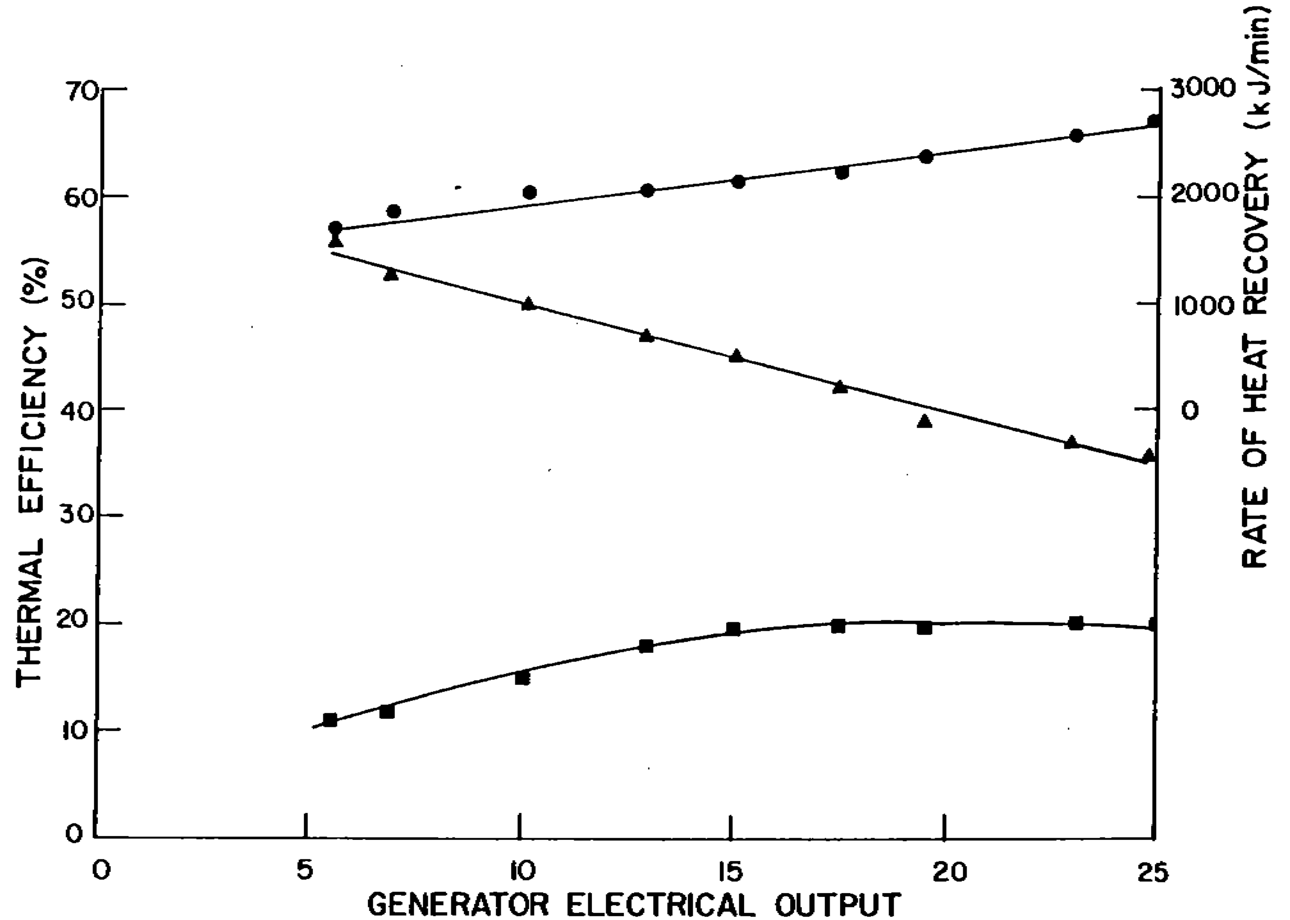


Figure 3.29. Performance of cogenerator at various loads ($\emptyset \cong 1.1$).

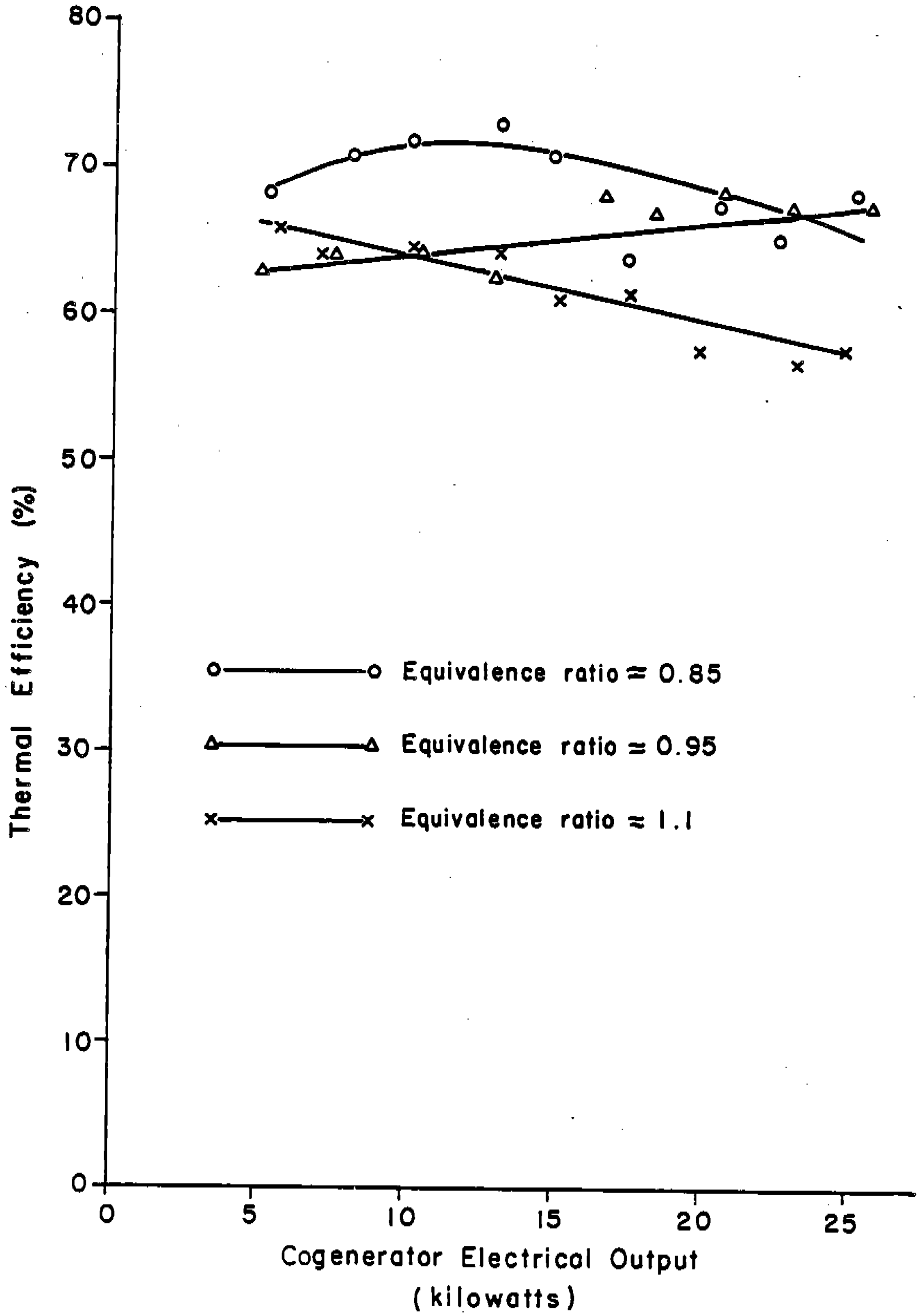


Figure 3.30. Combined conversion efficiency of biogas to electrical and heat (hot water) energy.

The heat exchanger on the engine coolant system proved to be the primary source of heat for the heat recovery system (Figure 3.31). The engine coolant heat exchanger provided about 57% of the available heat at rated load and up to 79% of the heat at 5 kW load. For loads greater than 15 kW no difference was noted for the three fuel-air mixtures as to the proportion of heat recovered from the coolant and exhaust. At loads less than 15 kW the leaner mixtures appear to result in a smaller proportion of the heat being reclaimed by the exhaust heat exchanger.

III.C.2. Reliability, Oil Analysis Tests, and Wear Observations

The engine was initially started in August, 1981. After only 193 hours of operation, the engine experienced an overheating problem and was severely damaged. A new short-block was installed, and the system was returned to operation in early January of 1982.

The early failure of this system reflects the need for extensive safety features of these systems and good communication between the user and the supplier. Examination of circumstances surrounding this failure did not satisfactorily identify the cause of the overheating. Controls to shut down the engine at high coolant temperatures, low oil pressure, low coolant levels, and overspeed should be standard equipment.

From the outset of this project, an attempt was made to gain some understanding of potential wear and maintenance problems that might be associated with combustion of biogas in an internal combustion engine. Although not entirely expected at the beginning of this project, the biogas contaminants in the fuel proved quite troublesome. Much of our attention eventually focused on the effects of these biogas contaminants on the lubrication oil and wear within the engine. During the 2500+ hours of operation of the cogenerator, the time was split between operation on raw biogas and biogas scrubbed by a Winslow biomass filter (See Appendix E for description of filter).

Our earliest observations of the oil analysis for operation of the engine on raw biogas indicated a rapid degradation of the ability of the oil to counter the accumulation of acidic contaminants. Initially, Kendall FL Select with a total base number (TBN) of 6.3 was selected. (See Table 3.7 for oil characteristics.) It was quickly noted that the TBN rating of the oil dropped below acceptable levels after short periods of use (Table 3.8). Based on Kendall's recommendation, their Super D-III with a TBN of 8.79 was tried next. It, too, proved incapable of counteracting the buildup of acidic contaminants in the oil. Finally, a third oil with a TBN of 10 was selected. The higher TBN oil provided only minor relief of the rapid deterioration of oil TBN level. The third oil selected was used in the engine for a single 250-hour interval. The TBN level of the oil dropped from an initial rating of 10 to the minimum acceptable level of 2 within 55 hours of operation. Additional operating time on the oil resulted in undesirably low oil TBN levels (see samples No. 8 through 12 in Table 3.8 and Figure 3.32). High TBN oils did not appear to be capable of countering the buildup of acid in our engine crankcase.

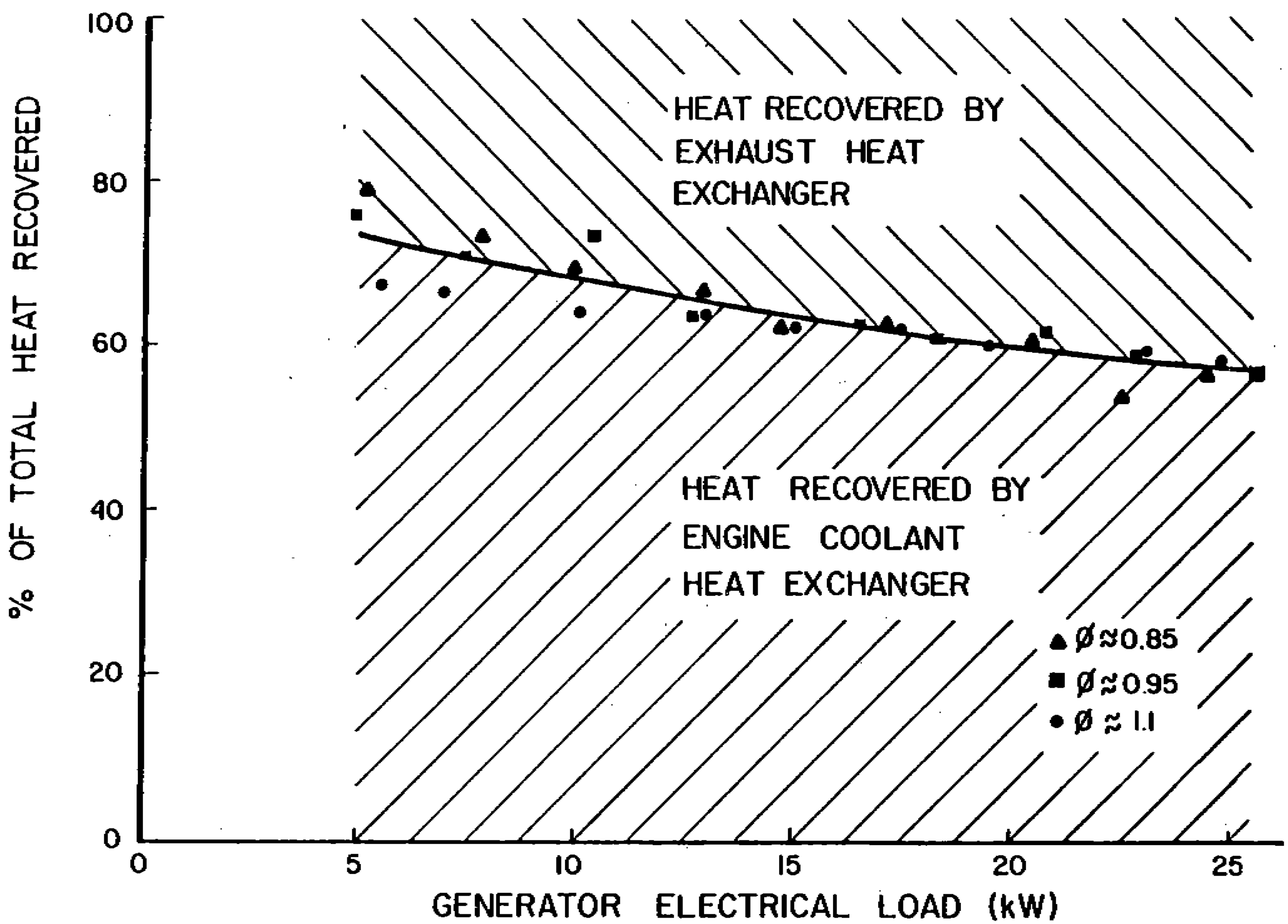


Figure 3.31. Proportion of heat recovered by exhaust and engine coolant heat exchangers versus load.

TABLE 3.7. SPECIFICATIONS FOR OIL USED IN COGENERATOR

API Classification	CB	CC	CC/SF	CD	CD/SC			SC SD SE SF							
Military and Industrial Specifications	MIL-L-2104A (S-1)	MIL-L-2104B	MIL-L-46152B	MIL-L-45199B (S-3)	MIL-L-2104C	EO-J (Mack Trucks)	EO-K (Mack Trucks)		Nat. Gas/ LPG-Low Ash (L) or High Ash (H)	Ash Content, % Wt.	Type ZDP and % Wt. Zn	Single Viscosity Grades	Multi-Viscosity Grades	Total Base No., D664	Total Base No., D2896
Brand Names															
Kendall FL Select	X	X	X			X*		SF		0.75	0.14 Alk	X	X	5.1	6.3
Kendall Super D 111	X	X	X	X	X	X*		SF		0.97	.146 Alk	X	X	8.11	8.79
Kendall Super D Select	X	X	X	X	X	X*	X*	SF		1.00	0.13 Alk		X		10

Reference: Engine Manufacturers Association, 1982

TABLE 3.8. SUMMARY OF OIL SAMPLES DURING OPERATION ON UNSCRUBBED BIOGAS

SAMPLE IDENTIFICATION				ANALYTICAL RESULTS						SPECTOGRAPHIC ANALYSIS											
Customer Sample No.	Hours On Unit	Hours On Sample	Oil	Meas'd SAE	% Water	Anti-Freeze	% Fuel Dilution	Solids	Varnish	Iron	Copper	Lead	Aluminum	Silica	Chrome	Tin	Sodium	Boron	TBN	TAN	pH
1	20	0	FL Select	30H	T		-	A	A	Nil	Nil	16	2	10	Nil	14	Nil	88	-	-	-
2	64	44	FL Select	40L	T		-	A	A	26	12	16	2	28	Nil	14	10	82	-	-	-
3*	114	94	FL Select	40L	T		T	A	A	52	20	22	4	38	Nil	30	10	86	.46	3.08	5.4
4	193	65	Super D-III	40L	T		-	A	A	42	24	16	Nil	12	Nil	10	Nil	106	1.75		5.2
5	255	127	Super D-III																		
6	368	72	Super D-III	40M	T		-	A	A	33	11	16	6	8	Nil	16	Nil	104	0		3.8
7	412	116	Super D-III	40L	1+		-	A	A	41	10	10	4	6	Nil	6	Nil	71	1.49		6.2
8	467	55	Super-D Select	30H	.5		3	A	A	20	18	10	Nil	19	Nil	5	20	100	1.99		5.9
9	527	115	Super-D Select	30H	T		-	A	A	37	29	Nil	Nil	13	Nil	Nil	20	102	.78		
10	567	155	Super-D Select	40L	T		1	A	A	93	39	Nil	Nil	18	Nil	Nil	20	86	.62		
11	620	208	Super-D Select	40L			-	A	A	186	52	Nil	Nil	20	Nil	Nil	30	79	.46		
12	653	241	Super-D Select	40H	T		-	A	A	206	52	5	Nil	21	Nil	3	30	82	1.42		4.2

Code: T = Trace, A = Acceptable, B = Borderline, E = Excessive

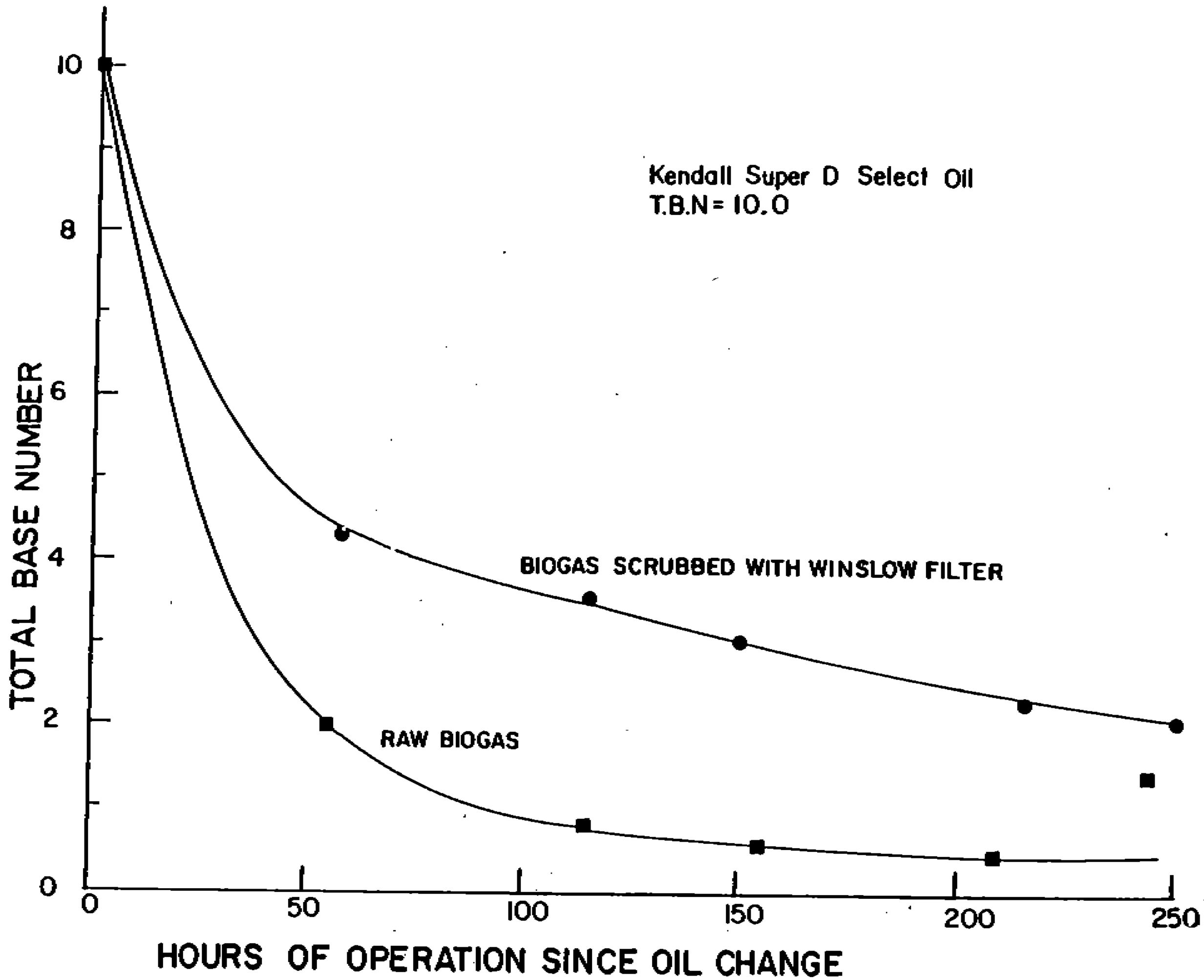


Figure 3.32. Total Base Number of oil versus elapsed time since oil change.

The oil analyses also identified one additional problem. The appearance of relatively high levels of silica and several wear metals was eventually traced to the slow decay of the insulation on the exhaust piping. Apparently vibration caused disintegration of urea solid insulation, and it was drawn into the engine with air. Removal of this insulation provided some reduction of wear metal accumulation.

After 1220 hours of operation the engine was partially disassembled for inspection. Representatives of Cummins Mohawk Diesel and White Engine assisted with the disassembly of the engine and inspection of the internal components. The disassembly of the engine included removal of the head and all valves from the head, removal of all pistons, and removal of two main bearings.

After the head was removed, the following observations were made of the top of the piston, engine head, and exposed valve surface in terms of carbon buildup (See Figures 3.33 through 3.36):

Cylinder #1: Moderate carbon deposits on top of piston; valves average condition.

#2: Light carbon deposits on top of piston; valves average condition.

#3: Light carbon deposits on top of piston; valves average condition.

#4: Heavy carbon and oil deposits on top of piston; valves in relatively good condition.

At this time it was decided that various pistons should be removed in order to check the condition of both the rings and rod bearings. The following observations were made:

Piston #1: Rings were in average condition. Valve guides were worn but within tolerances. Moderate pitting of the rod bearing insert surface was noted.

#2: Rings were in average condition. Valve guides were worn but within tolerances. Slight pitting of the rod bearing insert surface was noted.

#3: Rings were in average condition. Rod bearing inserts showed severe pitting of the bearing surface and some minor flaking away of the surface.

#4: Rings looked to be in average condition, and it was determined that the significant oil deposits on top of the piston were caused by a defective oil seal on the intake valve, which had been leaking oil during engine operation. Both intake and exhaust valves were removed from the head, and it was found that one exhaust valve and valve seat

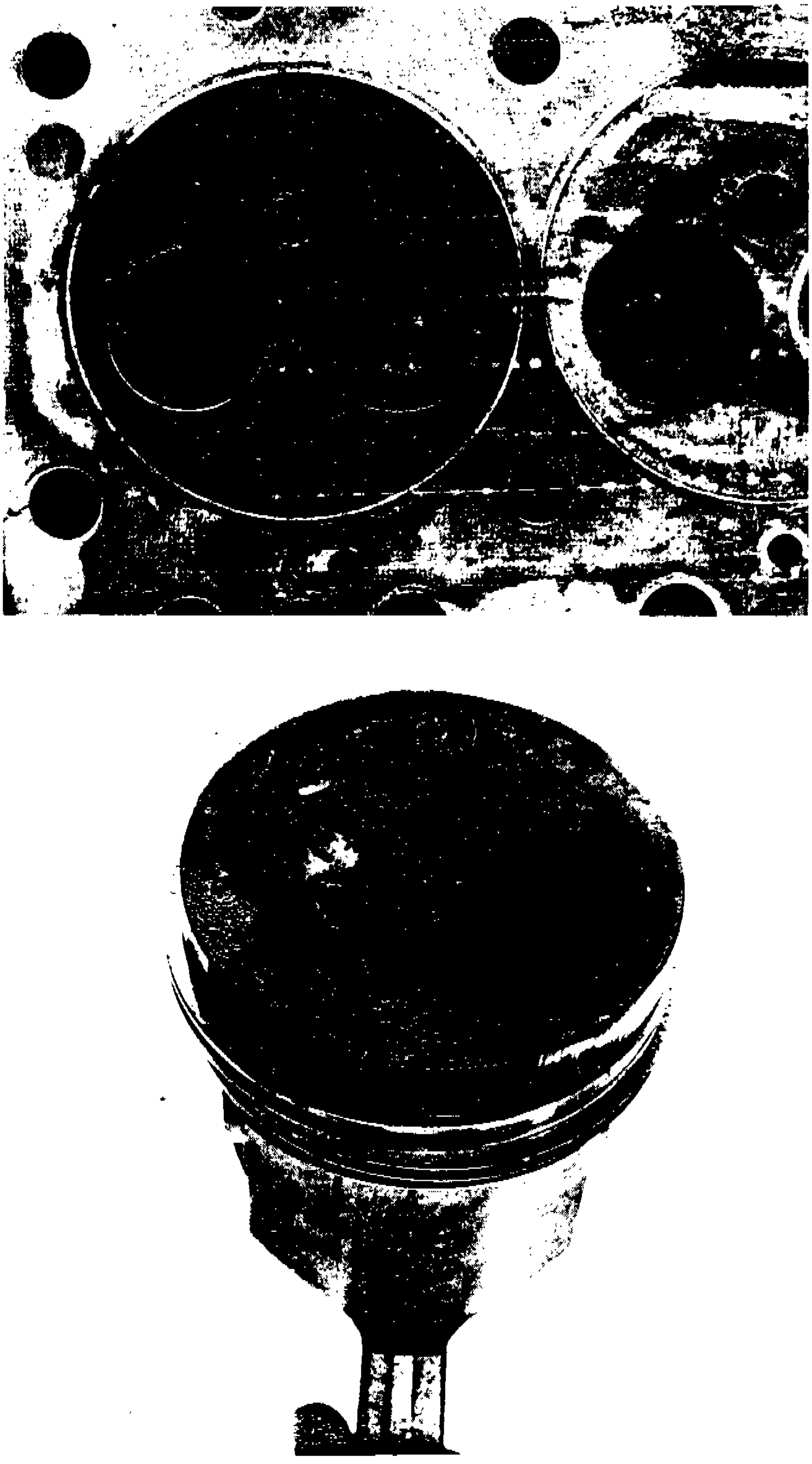
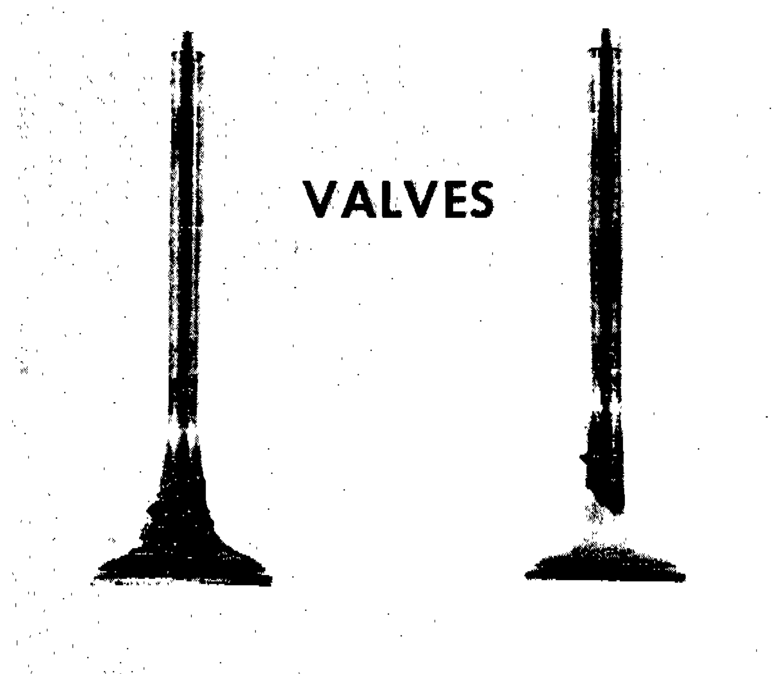


Figure 3.33. Photograph showing moderate carbon buildup noted in cylinder head and on piston after 1220 hours of operation on raw biogas.



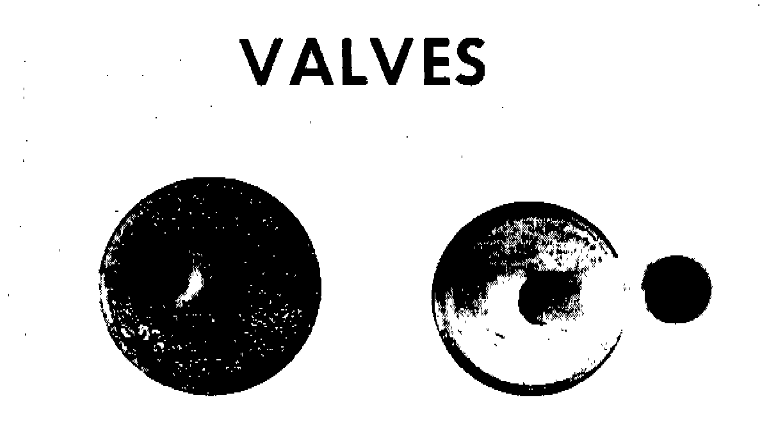


Figure 3.34. Few problems were noted with valves. Slightly excessive wear was apparent in valve guide area after 1220 hours of operating on raw biogas.

MAIN BEARING

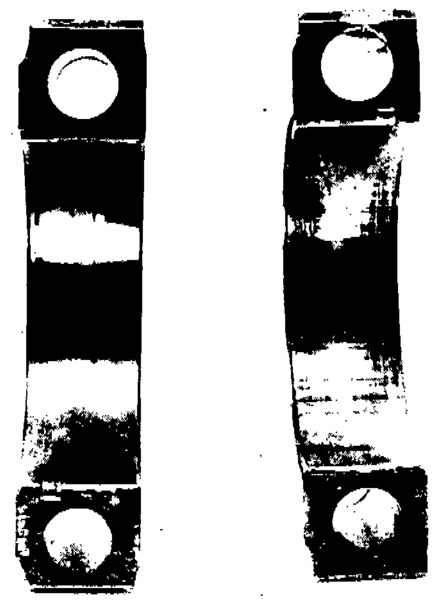


Figure 3.35. Main bearings were in satisfactory condition after 1220 hours of operation on raw biogas. No signs of surface pitting were noted.

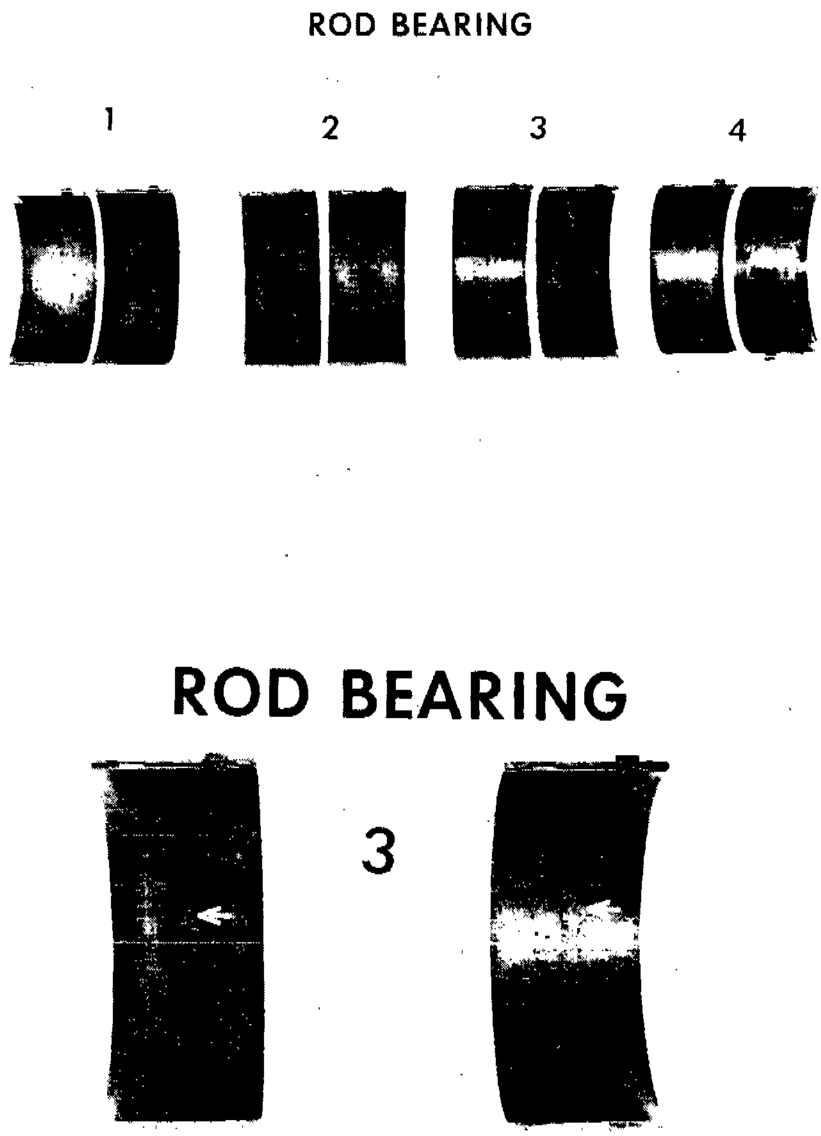


Figure 3.36. Rod bearings showing some pitting effect due to acidic oil conditions after 1220 hours of operation on raw biogas.

required replacement due to slight pitting of the contact surfaces. This mechanical damage was likely due to a faulty rotator. The rod bearing inserts showed average wear and some slight pitting of the surface. The valve guides were slightly worn but were within inspection tolerances.

Main bearings #2 and #4 were removed from the crankshaft and showed average wear, but no signs of the pitting were noticed on the ring bearing. Inspection of the cylinder bores showed some evidence of scoring, probably caused by carbon deposits in the piston ring grooves. Since the same piston rings were to be reused they were not removed from the pistons. Excessive carbon deposits were carefully removed. Score marks were found at the following locations: (Note: 12 o'clock is the front of the engine.)

Cylinder #1: 12 o'clock

#2: No evidence of scoring

#3: 3 o'clock and 10 o'clock

#4: 3 o'clock and 9 o'clock

All parts were completely cleaned and inspected prior to reassembly. The only difficulty encountered was correctly seating the front and rear oil pan gaskets that simply lay on the oil pan surface without guides of any sort. This required removal and reassembly of the oil pan and use of excessive amounts of gasket adhesive.

During reassembly of the engine the following parts were replaced: intake valve seals, exhaust valve rotators, exhaust valve and valve seat for #4 cylinder, rod bearing inserts, fan belt (which was found to be cracked), lower radiator hose, bypass hose, oil filter, air cleaner filter, and fuel filter.

All nuts and bolts were torqued according to manufacturers' specifications. The valve clearance was set according to specifications, and the engine was allowed to "run-in" for a period of one hour to allow complete warm-up, at which time the valves were given final adjustment.

For the most part, the engine was considered to be in fair condition. A report from the representative of White Engine Company generally supports this conclusion. (See Appendix H.) It should be noted, however, that 1,220 hours of engine operation is a small fraction of the desirable life of an engine between major overhauls. Two problems were observed that may be related to the fuel. The wear noted in the valve guides was slightly excessive. This can be expected from a gaseous fuel which does not provide any lubrication to this area as compared to a liquid fuel such as diesel. Moderate oil leakage between valves and valve guides may be necessary to prevent excessive wear in this area, or shorter than normal intervals for changing of guides may be needed.

The second and more serious problem was noted on the rod bearings (Figure 3.36). The rapid acidity buildup in the lubrication oil during operation on unscrubbed biogas appears to be the most likely cause of the pitting of rod bearing surfaces. The pitting that was noted was fairly small sized and numerous (Cummins, 1979). Bearing inserts on 1, 2 and 4 were fairly uniformly pitted. Only bearing 3 showed excessive damage to the surface in the form of flaking away of the surface material.

It should be noted that oil change intervals of 150 hours or less were used at all times except once when the oil was changed after 250 hours (Table 3.9). Oils with a Total Base Number of 6, 8 and 10 were used for 128 hours, 284 hours, and 808 hours, respectively. Our biogas contained hydrogen sulfide averaging between 3000 and 4000 ppm. Variations in biogas sulfur content may also affect the severity of this problem.

Prior to additional engine operation, a Winslow gas conditioner was installed for the specific purpose of reducing the effects of acid buildup in the oil. Oil analysis for the period following this modification indicated that the oil TBN level remained higher for much longer periods of time (Table 3.10 and Figure 3.32). Several samples indicated that the oil was maintaining reasonable TBN levels for 200-hour or more oil change intervals if a TBN of 2.0 is assumed to be a reasonable cutoff. Rather dramatic differences in oil TBN levels are shown for raw and scrubbed biogas tests over a 250-hour oil change interval in Figure 3.31. This information appears to support the value of the Winslow filter. From these findings, it was decided that an oil change interval of 250 hours would be used for operation on gas treated with the Winslow filter (Table 3.11).

During this time a constant problem was noted with the appearance of silica and wear metals in the oil. It was presumed that the wear metals were a result of the presence of silica in the oil and that the silica originated from outside the engine. An attempt had been made to reinstall exhaust pipe insulation with a protective coating to prevent its decay and eventual appearance in the oil. Because of its past history as a source of silica in the oil, the insulation was eventually removed. Oil samples 106 and 107 indicated that removal of the insulation solved the silica problem but did not reduce the wear metal levels. Within a short time, a major failure within the engine occurred at the 2504 hour mark (a rod broke through the side of the engine). The appearance of wear metals in the oil certainly provided an indication that a failure might have been imminent. However, the incorrect placement of the blame for the wear metals resulting from silica entering the oil and the arrival of the last oil sample report after the failure prevented us from foreseeing a possible failure.

The engine was again disassembled with assistance from representatives of White Engine and Cummins Mohawk Diesel and inspected. The engine was then returned to White for further inspection and testing. An engineering report from White places the primary failure at the No. 2 wrist pin bushing (See Appendix H for full report). This

TABLE 3.9. OIL CHANGE AND CONSUMPTION RECORD FOR OPERATION ON RAW BIOGAS

Oil Changes			Oil Added (Quarts)											
Date	Meter Hours	# Hours on Oil	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Remarks	Oil Used
4/23	128	108	0.5	118									New Engine	Kendall F-L Select
7/8	296	168	1	190	1/2	201	1	231	1	267				Kendall Super D-111
7/20	412	116	1	391										
8/15	653	241	1	501	1	621								
9/13	809	156	1	675	1	725	1	773						
9/27	971	162	1	888										
10/6	1115	144												
11/4	1220	105	1.5	1192	1	1216	1	1253					Engine torn down at 1220 hours	

TABLE 3.10. SUMMARY OF OIL SAMPLES DURING OPERATION ON BIOGAS SCRUBBED BY WINSLOW FILTER

SAMPLE IDENTIFICATION				ANALYTICAL RESULTS						SPECTOGRAPHIC ANALYSIS											
Customer Sample No.	Hours																				
	On Unit	On Sample	Oil	Meas'd SAE	% Water	Anti-Freeze	% Fuel Dilution	Solids	Varnish	Iron	Copper	Lead	Aluminum	Silica	Chrome	Tin	Sodium	Boron	TBN	TAN	pH
101	1279	58	*	40L	T		-	A	A	48	104	18	3	119	Nil	11	30	163	4.31		
102	1337	116	*	40M	T		-	A	A	89	83	24	3	128	3	18	30	142	3.56		
103	1370	149	*	40M	T		-	A	A	127	69	27	3	111	4	22	30	123	3.00		
104	1435	214	*	40M	T		-	A	A	212	70	24	4	113	7	29	40	112	2.24		
105	1470	249	*	40M	T		-	A	A	235	55	30	4	91	5	24	30	91	2.06		
106	2006	255	*	40L	T		-	A	A	295	134	68	7	38	4	48	40	72	1.90		
107	2333	225	*	40L	T		-	A	A	257	180	62	8	18	2	52	20	110	1.90		

Code: T = Trace, A = Acceptable, B = Borderline, E = Excessive
*Super-D Select

TABLE 3.11. OIL CHANGE AND CONSUMPTION RECORD FOR OPERATION ON SCRUBBED BIOGAS

Oil Changes			Oil Added (Quarts)											
Date	Meter Hours	# Hours on Oil	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Amt.	Hrs.	Remarks	Oil Used
1/18	1496	275	1	1252	0.5	1265	0.5	1275	1	1314	1	1356		Kendall Super D-Selat TBN=10
			1	1337	0.5	1411	0.5	1436	1	1475				
2/17	1752	256	0.5	1578	1	1639	1	1733	–	–	–			
3/21	2006	254	0.5	1902	1	1910	1	1937	–	–	–			
4/11	2108	102	1	2088	–	–	–	–	–	–	–		Water in Engine	
5/1	2333	225	1	2192	1.5	2270								
5/20	2505	172	1	2940	1	2465							Engine Failure	

resulted in a failure of a connecting rod bolt and a connecting rod. The remaining wrist pin bushings exhibited a loss of copper liner material and extreme clearances between the pin and bushing as a result of the wear. White personnel attributed this problem to "the affects of corrosive action of acid-like contaminants present in the biogas fuel..." The wrist pin bushings are a leaded bronze material (SAE No. 792) made by Clevite. They are composed of 80% copper, 10% tin, and 10% lead with a steel backing.

In addition, all rod bearing inserts exhibited a considerable number of pinhead-sized pits on the insert surfaces. Two of the inserts also exhibited areas where patches of bearing surface material of approximately 2 to 5 mm in diameter had flaked off (Figure 3.37). The main bearings, which appeared in good condition at the 1220 hour teardown, now exhibited numerous signs of surface pitting (Figure 3.38). The rod bearing inserts and main bearings had been in place 1280 and 2500 hours, respectively. The rod bearing inserts and main bearings are a Tri Metal F-77 made by Clevite. They consisted of 87.5% lead, 10% tin, and 2.5% copper (SAE No. 49) and were flash tin plated all over per SAE No. 19. In addition, severe wear was noted by White on the contact face of the tappets, on the camshaft lobes, and on the camshaft drive for the oil pump. The observation of the type of wear noted in the engine seems to conflict with the assumption that changing the oil at a TBN level of 2 was acceptable.

An analysis of the Winslow gas conditioning filter was also requested from Winslow filtration. They reported that the base chemical level of the filter had dropped from a pH of 10.25 when new to 8.32 after 1280 hours of use for scrubbing the gas supply to the engine. Winslow's test report stated that "elements must be changed when pH reaches 8.25. There was a small amount of active base in the media" (see Appendix H for full report). Apparently, the filter was capable of performing its function throughout the test period when it was in use.

III.C.3. Appraisal of Cogenerator

The following discussion is an attempt to verbalize the experiences gained from working with a cogenerator over a 2500 hour operating period that have not already been quantified. Over this period the cogenerator produced in excess of 40,000 kWh of electricity and about 290 million kJ's of heat energy as hot water, of which about 67 million kJ's were delivered to the dairy to replace water heating needs (Table 3.12). This experience provided several insights into strengths and weaknesses of the equipment.

The single greatest strength of this package had to be the induction generator. The simplicity of connecting it to the utility electrical service plus the lack of problems of operating in parallel with the utility made this feature a very trouble free part of the system. Initiating generation of electricity in parallel with the utility required bringing the engine up to a speed slightly above synchronous speed of the generator, then closing a breaker, and

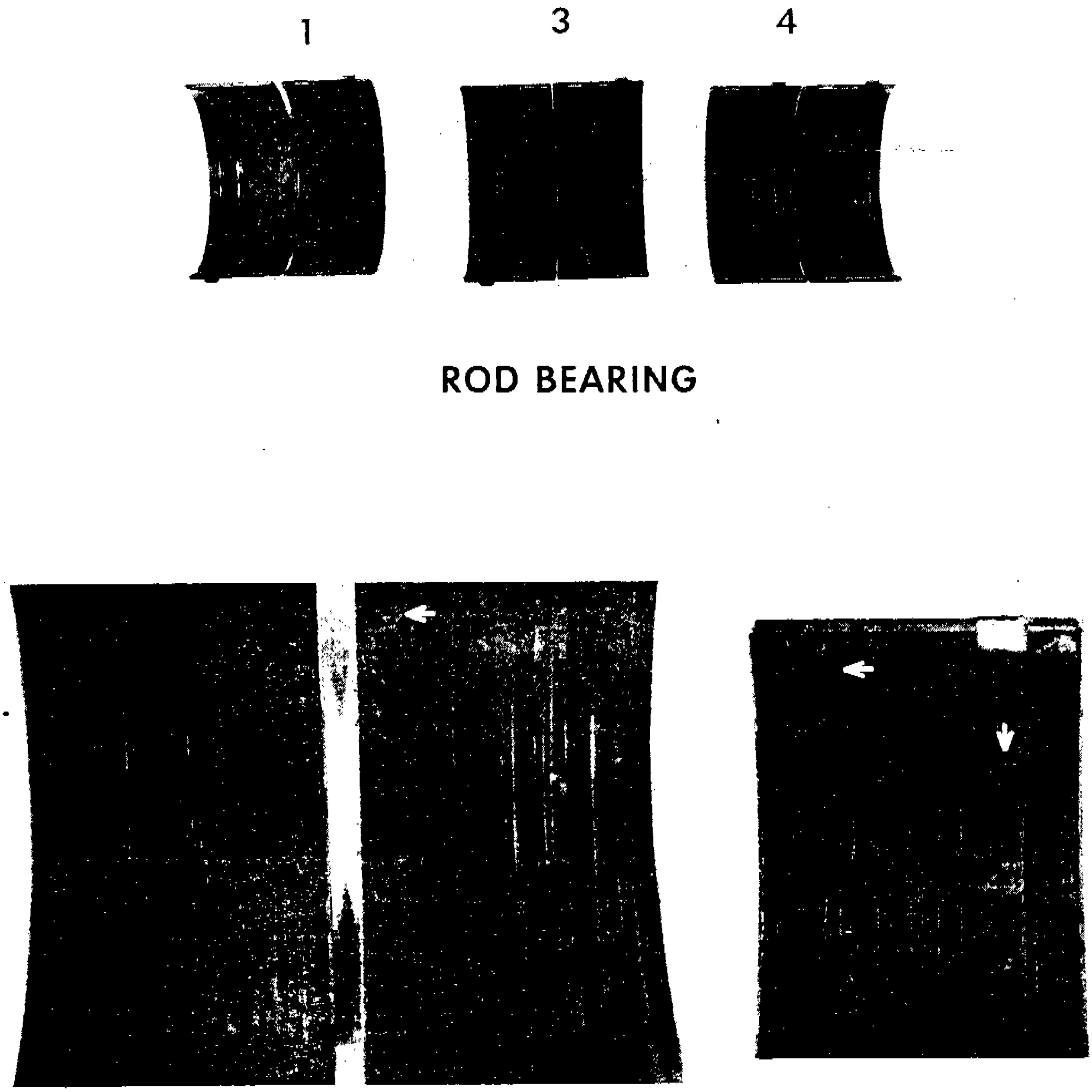
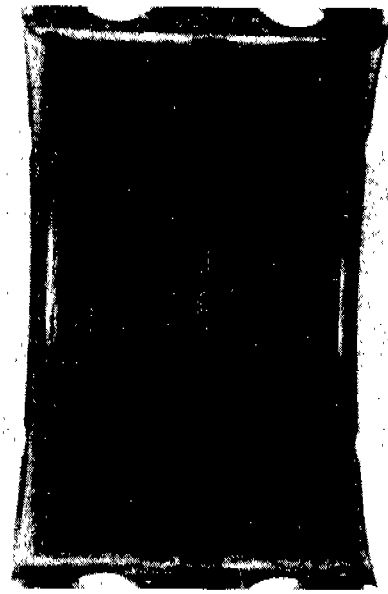


Figure 3.37. Rod bearing after 1280 hours of operation on biogas scrubbed by the Winslow gas conditioner. The scratch marks may have been caused by the engine failure. Note the"salt and pepper" pitting that appeared during the 1280 hours of operation (see arrows).



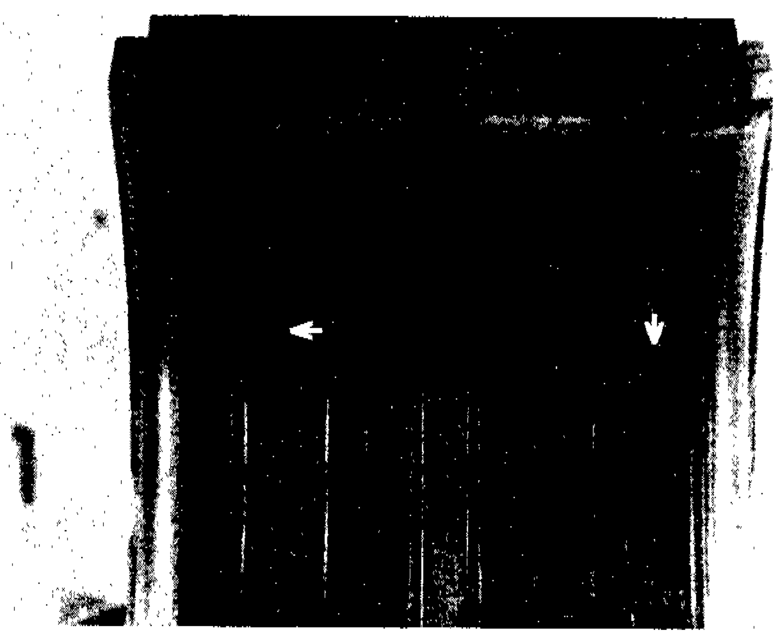


Figure 3.38. Main bearings after 1220 hours of operation on raw biogas and 1280 hours of operation on biogas scrubbed by Winslow gas conditioner. The salt and pepper pitting has appeared in the 1280 hours of operation (see arrows).

finally adjusting the electrical output of the generator by means of the engine throttle to the desirable level. There were no concerns with proper phasing of the generator to the utility as one would have with a synchronous generator. It was essential to have a reverse power relay that would prevent the generator from motoring. Several situations exist where the engine might shut down without someone being present to disconnect the generator from the line, thus allowing the generator to motor without reverse power protection.

TABLE 3.12. QUARTERLY SUMMARY OF COGENERATOR ENERGY PRODUCTION

Quarter	Operating Hours	Electricity Produced (kWh)	Heat Delivered to Dairy (KJ x 1,000)
1st	0	--	0
2nd	59.1	0	--
3rd	250.4	3,429	--
4th	589.6	10,130	26,680
5th	771	12,356	20,050
6th	446	3,197	6,390
7th	568	8,528	12,450

The electronic governor and the shunt trip 150 amp breaker for the generator proved to be the weak points of the system. Two electronic governors failed during this project, and at the project's end the electronic governor had been replaced by a mechanical governor. Although the electronic governor was of some value to our testing program, there is no reason why a commercial installation cannot make use of a more reliable mechanical governor. Twice during this project mechanical parts of the 150 amp shunt trip breaker failed. The shunt trip mechanism was used almost daily to remove the generator from the electrical service as gas production ran low. Other methods of daily connection and disconnection of the generator may need to be considered. At one time after two failures it was thought that the reverse power relay was also a weak point of the system. However, the problem was traced back to an inappropriately sized shunt trip in a new 150 amp breaker that was installed. This resulted in excessive current flow through the reverse power relay. Installation of the appropriate shunt trip mechanism would have prevented all problems with the reverse power relay noted in this study.

The controls for protecting the engine against a failure proved adequate, with one exception. It would be desirable to have a sensor that would shut the engine down when excessive vibration is noted. The period prior to our engine failure was characterized by a 2.5 hour period of moderate engine vibration and a 1.5-hour period of excessive vibration (Figure 3.39). If the engine had been shut down during this period, serious damage would have been avoided. The controls for shutting down the engine on over-temperature and overspeed conditions occasionally proved valuable. Controls for stopping

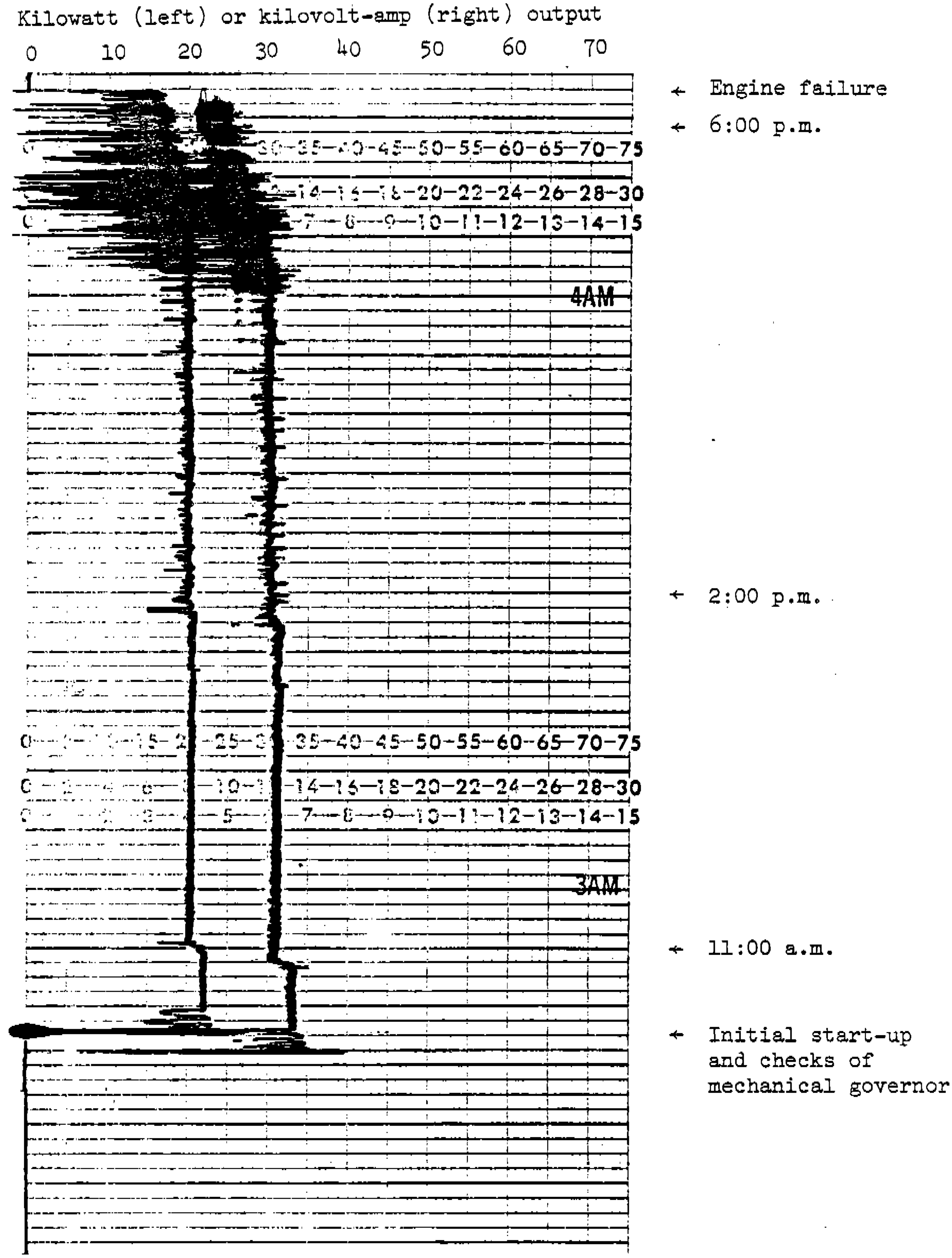


Figure 3.39. Electrical output of generator on the day of engine failure (May 20, 1983).

engine operation during low coolant level and low oil pressure situations were available but not employed during this study. However, they are critical components to a protection package.

Some minor problems were also noted with the spark system. The electrical contacts in the cap, the rotor contacts and the mechanical breaker points of the distributor required cleaning at intervals of anywhere from 50 to 500 hours. These electrical contacts often became tarnished with a dark residue in a very short time, resulting in rough engine operation. Cleaning of these parts and resetting of the breaker points generally corrected the problem. In addition, the ground electrode on the original spark plugs installed decayed rapidly causing the gap to increase from 0.076 cm to 0.114 cm (0.030 to 0.045 inches) in 100 hours of operation. The electrodes of these plugs were made of a nickel alloy. Plugs with an inconel electrode replaced the original plugs, and a plug change interval of 500 hours was then established with no problems.

Early in the study rough operation was a constant problem. Proper setting of the spark system (discussed earlier in this chapter) and proper mixing of the fuel and air were the primary problems. By increasing fuel supply pressure from less than 15 cm (6 inches) of water pressure to 25 cm (10 inches) and insuring a constant gas supply regardless of upstream pressure or flow rate, improvements were effected in operation. The installation of a positive pressure carburetor in place of a updraft negative pressure carburetor provided additional assistance with this problem. Once the proper fuel-air mixture and spark timing was attained, very few problems were noted with rough engine operation.

The heat recovery and utilization system went through a number of modifications before working entirely satisfactorily. Our experiences with this system illustrated that its design includes at least four general requirements.

First, it is essential to provide an adequate means of wasting heat from the system at the same rate at which heat is recovered from the engine to avoid overheating of the engine. To provide for this situation, two methods of heat dump were built into the heat recovery loop (see hot water system diagram in Appendix F, Figure F-3). An air-cooled radiator was installed with an electric fan actuated by the temperature of the water returning to the engine coolant heat exchanger (point A, Figure F-3). For temperatures in excess of 60°C water would be directed through the radiator, and the fan would switch on at 63°C. Additional protection was provided in the form of a solenoid valve that dumped hot water for return temperatures in excess of 66°C and replaced it with tap water. This procedure of dumping heat proved satisfactory for protecting the engine. One additional improvement would be to key operation of the loop 2 circulation pump to operation of the engine (Figure F-3). This would prevent starting of the engine without the circulation pump operating.

The heat recovery and distribution loop (loop 2, Figure F-3) must be capable of maintaining a minimum return water temperature to the engine coolant heat exchanger after the initial start-up of the engine. Automatic mixing of the return water with with hotter water in the same loop allowed the system to maintain a minimum temperature level of return water for all except the first one-half hour of operation. This measure is desirable to help maintain the engine coolant at a minimum desirable temperature. Without this mixing valve, we noted prolonged periods of operating the engine coolant at reduced temperatures that might contribute to greater wear problems and less fuel efficient operation.

The digester heating system should be capable of receiving heat at a rate equal to the maximum potential rate of heat produced by the cogenerator. Our cogenerator produced heat more rapidly than our digester heating systems could conduct it to the manure. This was a constant problem for our system that became apparent during cold weather and times of low gas production, which resulted in shorter engine operating time. At these times it became difficult to maintain digester temperature despite there being additional heat available from the cogenerator that could not be delivered to the digester. Sizing of the digester heating system to match the heat production rate of the cogenerator is desirable.

Finally, it is important to design the heat distribution system so that various uses of heat have different levels of priority. The digester should be given highest priority, with home and dairy needs receiving a secondary priority status. Our system provided heat to the digesters at any time that digester temperature dropped below acceptable levels. Heat was provided to the dairy only at times when the digesters were not capable of absorbing all of the available heat. This was accomplished by activating a pump in the dairy hot water loop (loop 3, Figure F-3) only when the return water in loop 2 was above an acceptable level (60°C).

It was also noted that the quality of heat from the generator (85 to 90°C) was not entirely compatible with the generally accepted requirements of a digester heating system (60°C). From July 1982 through May 1983 the hottest water produced by the cogenerator was directly used in the digester heating system. The conductive heat transfer of the plug flow digester heating system was checked on three occasions (Table 3.13). Over this short period of time the conductive heat transfer rate of the heating system remained relatively constant at roughly 42 watts per square meter per degree centigrade. However, these data can by no means be considered conclusive. Observation of digester heating systems in two other digesters following a similar practice revealed some potential problems.

TABLE 3.13. CONDUCTIVE HEAT TRANSFER RATE OF A PLUG FLOW DIGESTER HEATING SYSTEM

Test Date	Average Water Temperature (°C)	Average Manure Temperature (°C)	Heat Transfer Rate	
			KJ/hr	Watts/m^2-°C
9/ 5/82	74	35	86000	43
11/20/82	71	33	86500	43
2/23/83	79	38	89100	42

One final observation should be made relative to the location of the cogeneration system. Our unit was located in the immediate proximity of two digesters and several manure storage facilities. The environment inside the building housing the cogenerator was apparently slightly contaminated with sulfur-based gases. Its presence is presumed to be responsible for any copper piping, copper electrical contacts, or other copper materials quickly becoming tarnished with a dark residue. It may be wise to consider moving the cogenerator away from the digester and other manure storage facilities and providing good ventilation for any structures housing such equipment. Consideration should also be given to packaging of motors, generators, controls, and electrical contacts in gastight containers to prevent the potential harmful effects of sulfur-based gases and miscellaneous dusts.

CHAPTER IV

DISCUSSION

IV.A. BIOGAS GENERATION

The results of long-term testing of dairy manure digestion continued to show that the low cost plug flow digester was a more efficient and lower cost alternative. The difference in removal rates between 8 and 22 days hydraulic retention time was about 0.5 gm TVS/ℓ-d. Then, on average the plug flow reactor produced about 1 volume of biogas per volume of reactor per day more than the completely mixed, with decreasing difference at the longer retention times or lower loading rates. Total volatile solids conversion efficiency was 6 to 8 percent higher with the plug flow system compared to the completely mixed reactor.

In order to increase total gas production to provide longer test duration with the cogeneration system, alternatives to increase total production were examined. Since we were dissatisfied with the top design and the hold down system, the entire cover for the flexible digester was redesigned. The new design provided a concrete collar with a wet sealed hold down fastening system that was easy to construct and used existing off-the-shelf components. New flexible material, XR-5, was considered to be a much improved cover for digesters.

These modifications were incorporated in a new design in a five-week construction period. The plug flow reactor volume was increased from 40 to 93.5 m^3 without the necessity of shutting down the unit, and at a minimum capital cost.

The new plug flow design appears to be a substantial improvement over previous designs. However, during modifications it was decided to omit the effluent baffle. One tracer test and the resulting overall performance showed that omission of this baffle caused some reduction in performance and caused, most likely, short-circuiting.

In order to take advantage of increased gas production potential and the increased system size, modifications to eliminate short-circuiting were considered. A review of design alternatives had shown that a pre-mix and heating tank prior to the plug flow reactor would have a number of advantages. Thus the full scale systems were modified so that the 38 m^3 completely mixed reactor effluent was fed directly to the 93.5 m^3 plug flow unit. Although this flow rate exceeded the heating capability of the completely mixed system, it resulted in more stable operation and a higher gas production. Daily biogas production of over 170 m^3 enable continuous operation of the cogenerator, whereas only intermittent operation had been possible in the other parallel system.

IV.B. BIOGAS HANDLING AND STORAGE

The biogas handling and storage alternatives represented a wide range of variables ranging from large volume atmospheric pressure storage to intermediate pressure. The large pillow tank (38 m^3) added flexibility and low cost gas storage. The incorporation of physical switch controls with the inflatable unit enabled safe and flexible operation of the system. Also blowing the biogas directly to the system proved to be an easy alternative, but more difficult to control.

The use of pressurized storage enabled short-term shutdown and gas accumulation. However, it is doubtful as to whether this type of storage could be economically justified.

Several materials deteriorated during the study. Replacement of the hypalon top with the XR-5 after three years of use enabled examination of the used material. It showed significant delamination of the seams exposed to the biogas and appeared to be close to the end of its useful life. Folding and sealing the edges of the hypalon to prevent movement of the biogas into the scrim could eliminate this problem.

A more serious, but less well defined problem is the accumulation of the wet, black "gunk" that coated the insides of all biogas transmission equipment. In an attempt to clear a pipe and valve on the pressurized gas storage unit, a valve was opened while the unit was pressurized. About two gallons of this material was blown from the tank, coating everything within 10 feet with material that looked like thick, black paint. It is likely that this material was partially produced by the high hydrogen sulfide levels in the biogas. Small quantities of this material could cause damage to mechanical devices, gas meters, etc.

A final observation that was made during subsequent shutdown of the unit was deterioration of the concrete collar. A weather cover and insulation (fiberglass) was placed over the concrete collar. Upon removal of this cover, severe corrosion of the concrete was observed. Up to 0.5 cm of concrete was dissolved in areas outside the digester.

IV.C. COGENERATION

Operation of a spark ignition engine on biogas provides some interesting challenges. With proper selection of spark timing and fuel-air mixture, smooth and efficient operation of the engine can easily be achieved. However, maintaining wear related to the sulfur in the fuel at a reasonable level may prove to be a more challenging problem.

Initial operation of the engine provided some problems related to misfiring and general rough operation. Proper timing of the spark system and adjustment of the fuel-air mixture proved to be the two key factors for eliminating such problems. In our situation, proper adjustment of the fuel-air mixture required installation of a positive pressure carburetor and increased pressure at the carburetor inlet to 25 cm (10 inches) of water pressure in addition to adjustment of the mixture control on the carburetor. No specific effort was made to evaluate the limits of mixture settings which would produce smooth operation. Our tests involved mixtures ranging from an equivalence ratio of 0.78 to 1.3, and operation was generally smooth over this range. Occasional misfiring problems were noted for $\phi = 1.3$, especially if some time had elapsed since maintenance on the distributor or spark plugs.

Spark timing also proved to be a relatively critical factor. Recommended timing for our engine when operating at 1800 R.P.M. on natural gas and LP-gas was 22 and 16 degrees BTDC, respectively. At this setting rough engine operation was generally noted in the form of muffled misfiring. To eliminate this problem, advancing of spark timing was necessary. At rated load, advancement of the spark timing an additional 15 to 20 degrees was necessary to achieve smooth operation and maximum power output from the engine. Apparently the dilution effect of the carbon dioxide in the biogas slows the flame speed in the cylinder. Additional time is needed for combustion of the fuel to advance through the cylinder so that maximum pressure rise occurs immediately after top dead center. It may be desirable to look at engine designs that speed combustion within the cylinder and reduce the spark advance needed. Slow combustion within the cylinder not only requires greater spark advance but also increases the amount of negative work done by the engine prior to the cylinder reaching top dead center (Obert, 1973). Such features that promote greater turbulence within the cylinder might offer some advantage for reducing negative work and improving efficiency as well as reducing spark advance requirements.

The spark timing needs of our engine operating on biogas corresponded closely with the findings of Stahl et al. (1982b) at heavy loads. However, at part loads our findings indicated that a less advanced timing was needed while Stahl et al. (1982b) concluded that spark should be further advanced for optimum engine performance. Stahl describes optimum engine performance as minimum brake specific fuel consumption, while our studies for determining a desirable spark timing were based upon the minimum spark timing at which peak power output for a particular throttle setting was achieved. These two different parameters for selecting an optimum spark advance only partially explains the discrepancy of the two studies.

Two additional factors, spark plug heat range and gap, were checked for their influence on engine operation. It is generally recommended for gaseous fuels that colder spark plugs and smaller gaps be selected (Champion, 1973). For the range selected for plug gap (0.043 to 0.076 cm) and heat range (Champion J-6, J-8, and RJ-10), little or no difference was noted in smoothness of engine operation. It may be desirable for operation on biogas to use smaller plug gaps and the hotter plugs. Hotter spark plugs are generally preferred for "sour" gas fuels (Champion, 1973). The smaller gap may partially counter rough engine operation that we occasionally noted due to the erosion of the plug electrodes that resulted in excessive plug gaps.

An evaluation of the thermodynamic performance of the cogenerator revealed few surprises. However, the consequences of selecting operating conditions based upon fuel use efficiency may be the more dramatic consideration. As expected, peak electrical efficiency was observed at lean fuel-air mixtures and near fully loaded conditions. Peak power was noted near stoichiometric conditions. Similar findings were also reported by Stahl et al. (1982b) and are characteristic of most other gaseous fueled engines (Obert, 1973). Heat recovery efficiency peaks at lean fuel-air mixtures and at part load conditions. At rated load conditions, up to 25% and 45% of the electrical and heat energy, respectively, were recovered.

These observations reveal that lean carburetor settings and loads approaching the cogenerator's maximum will be desirable operating conditions, if electricity has a higher value than hot water. Operation at $\emptyset = 1.1$ rather than $\emptyset = 0.85$ would result in 24% less electricity per unit of biogas being produced (Figure 4.1). Considering the relatively small adjustment in carburetor setting between these two mixtures and the inability of most equipment suppliers or farmers to distinguish between these two settings, errors of such magnitude or greater may be quite common. For a digester on a 250-cow dairy producing 425,000 liters of biogas a day, a setting of the carburetor for $\emptyset = 1.1$ rather than 0.85 would reduce the potential annual electrical production from 219,000 to 166,000 kWh. At 8 cents per kWh, this would represent an economic loss of $4,300 annually.

In a similar light, operation at loads less than about 60% of maximum power may cause some relatively large reductions in electrical production (Figure 4.2). Our unit will produce 28% less electricity per unit of gas during operation at 10 kW as opposed to 25 kW ($\emptyset = 0.85$). Oversizing of the cogenerator to the digester may result in operation at reduced electrical outputs (assuming 24 hour/day operation). In our previous example, our 25 kW unit would be properly sized for a digester producing 425,000 liters of biogas a day. However, use of this same cogenerator on a digester producing biogas at one-half the rate would force the cogenerator to operate at between 8 and 9 kW and reduce the potential electrical production by two-thirds. Thus oversizing of the cogenerator to the digester can have disastrous results in terms of electrical production.

If electricity is the product of greatest value produced by the cogenerator, several important steps should be taken to promote efficient conversion of biogas to electricity. First, the unit must be sized to allow operation at 60% of maximum power or more. It may even be best to undersize the cogenerator rather than oversize it even if it occasionally wastes gas. Next, during installation it would be desirable for the installer to check the fuel-air mixture provided by the carburetor. Since simple procedures are not always available to an installer, it would be desirable to first find the point at which maximum power is attained. Then a leaning of the

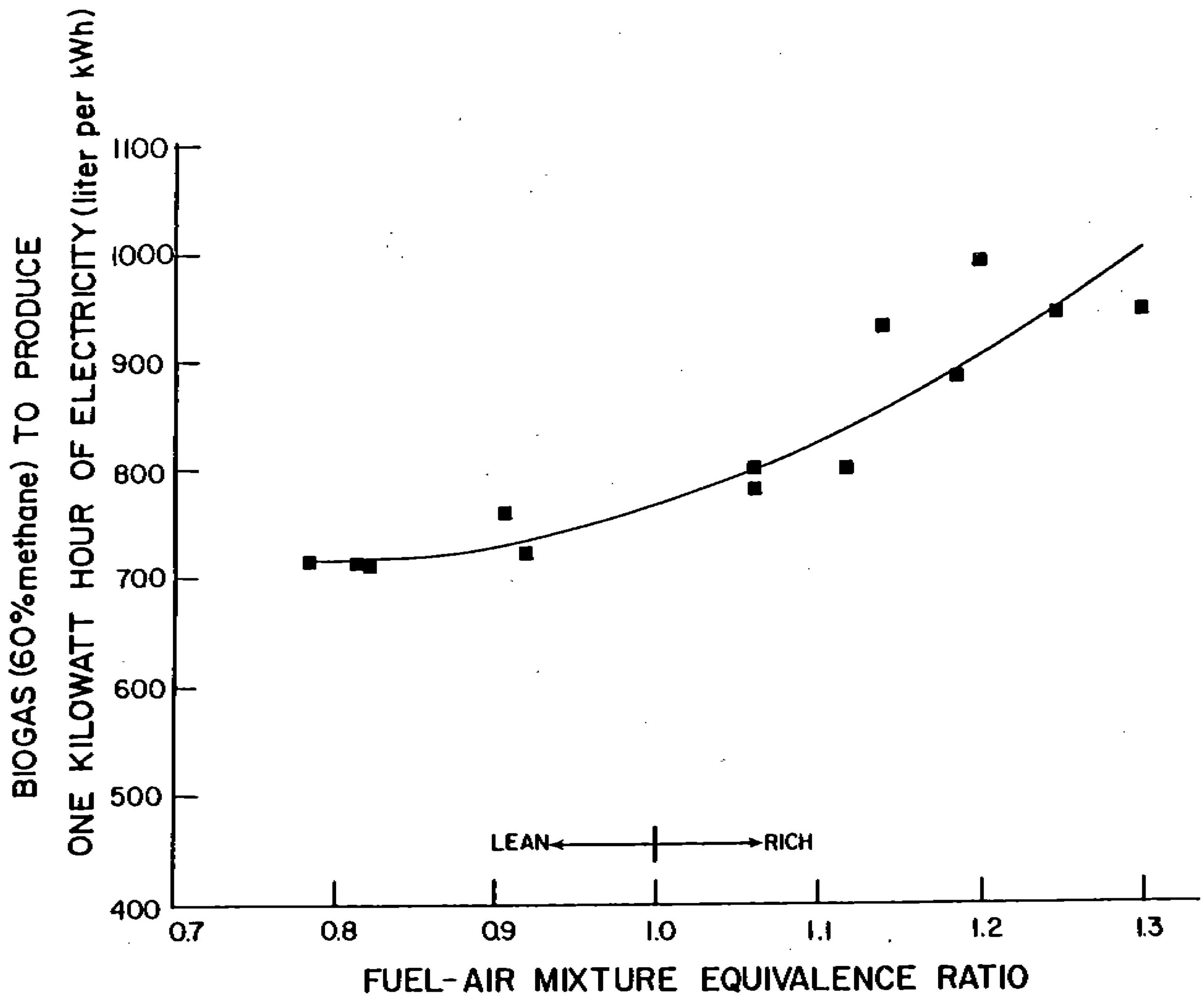


Figure 4.1. Comparison of gas consumption per unit of electricity produced for various fuel-air mixtures (25 kW load).

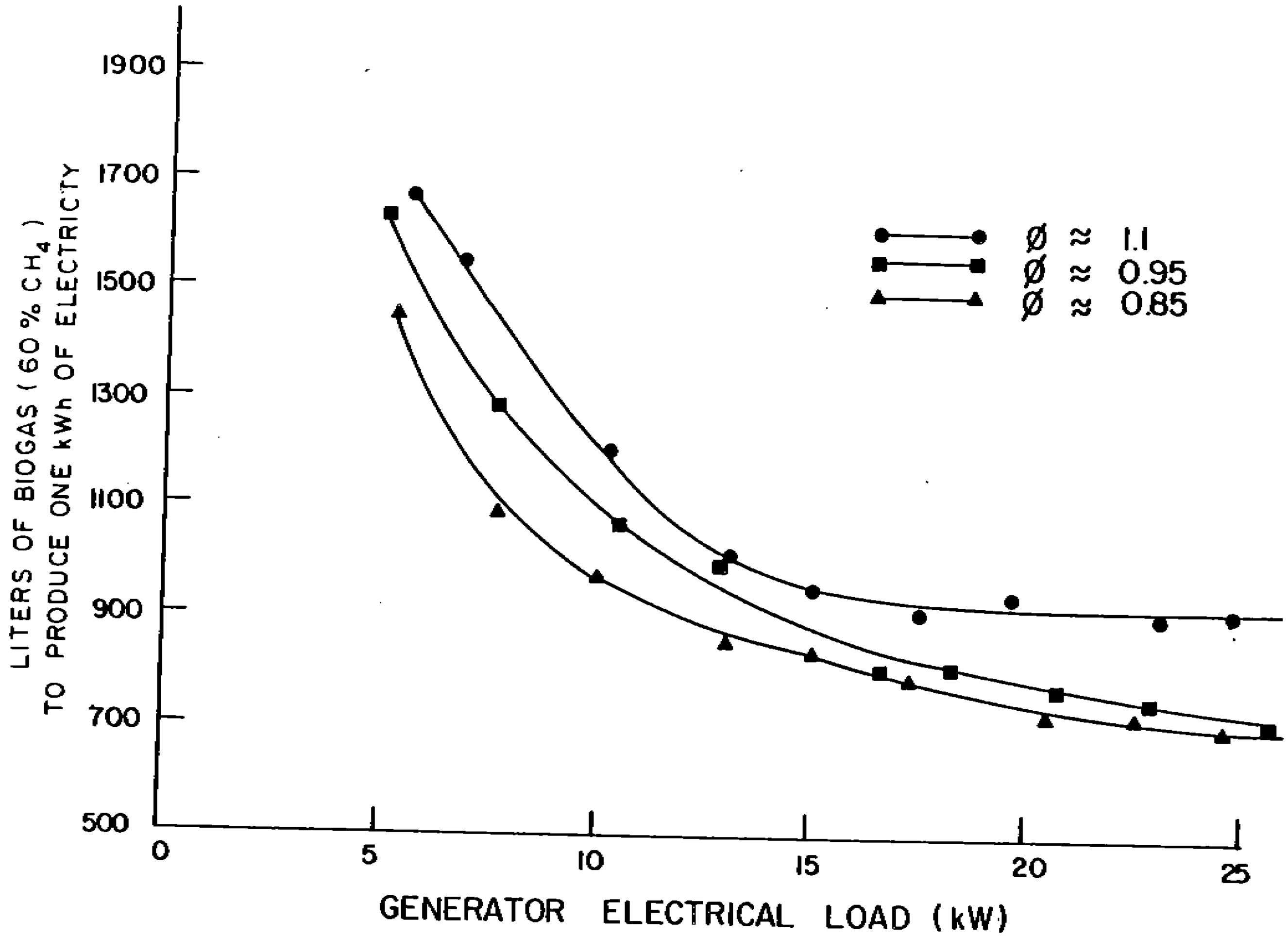


Figure 4.2. Comparison of gas consumption per unit of electricity produced at various loads for a 25 kW capacity unit.

fuel-air mixture that results in a 10 to 15% reduction in maximum power should provide a reasonably efficient setting for the carburetor. Finally, it would be desirable for the farmer to keep daily records of the volume of gas consumed by the engine per kilowatt-hour of electricity produced. Meters for measuring these two quantities should be considered an essential part of the instrumentation for any farm installation and possibly be included as part of the cogeneration package. It should be the aim of the farmer to maintain the gas consumption of the cogenerator at a level of 800 liters per kWh (28 cubic feet per kWh) or less. If the unit's gas consumption exceeds this level or if a continuing increase in gas consumption is noted, this may be an indication of the need for maintenance, low average loads, or other developing problems. These three measures will have a major impact upon the financial return of the cogeneration system.

If the hot water energy produced by the cogenerator is of equal or greater value than the electricity, then the operating strategy will change. Lean operation will still produce the most efficient recovery of biogas energy as hot water or electricity. However, operation near maximum load becomes less critical. The total energy recovered by our cogenerator was relatively constant for all loads. The additional efficiency of the heat recovery system at part load offsets the loss of electrical efficiency noted in this mode of operation. As the hot water energy becomes more valuable relative to the electricity, less concern may be placed on operating the engine near its maximum power.

The most perplexing problem encountered during this study was related to the contaminants in the biogas. The main contaminant, hydrogen sulfide, varied between 3000 and 6000 ppm (Table 4.1). This level is considerably higher than levels found in municipal digesters. It also appears to be equal to or higher than readings noted for several other digesters on commercial and research dairies in New York State. The severity of the problems observed during this study were likely influenced by the high level of hydrogen sulfide from our two anaerobic digesters. Other installations may not experience as severe or rapid an occurrence of the problems we noted depending upon the level of hydrogen sulfide in the biogas.

The most excessive levels of wear of engine components were noted primarily for those parts containing some copper (i.e., wrist pin bushings and bearings). Acidic accumulation in the oil resulting from the hydrogen sulfide in the biogas was considered to be the primary cause for excessive wear of these components.

Two major efforts were initiated to counter the effects of the hydrogen sulfide. Initially, oil with high TBN ratings (up to 10) was selected. However, this alternative did not allow the oil change interval to be extended to a reasonable level. Use of an oil with a TBN of 10 and oil change intervals averaging 150 hours resulted in degradation of the rod bearings after only 1220 hours of operation. High TBN oils are desirable for this application but alone were not capable of protecting the engine for normal oil change intervals. For the final 1280 hours of operation, a Winslow filter was employed for gas treatment. This filtering mechanism in conjunction with 250-hour oil change intervals also proved incapable of adequately protecting the engine from the effects of the hydrogen sulfide. It did slow the rate of decay of the TBN level of the oil but not enough to allow oil change intervals of 250 hours. Additional measures will be necessary to adequately protect the engine.

TABLE 4.1. RECORD OF HYDROGEN SULFIDE LEVEL IN BIOGAS

Date	Level (ppm)
3/16/82	6000
5/27/82	5000
7/13/82	2400
7/22/82	3400
7/23/82	3000
8/3/82	4000
10/1/82	4000
11/9/82	6000
1/8/83	3000
2/20/83	4000
3/13/83	3000
4/17/83	3500

At the beginning of these tests two assumptions were made that might also share the blame for the rapid wear observed. First, an oil TBN level of 2 was considered to be an acceptable limit for determining oil change interval (assuming TBN was the limiting factor). Although this was not closely adhered to during the first test period on raw biogas, it was closely followed during the final 1280 hours of operation. Possibly a higher cutoff point, such as TBN equal to 4 as suggested by Waukasha, should be considered. If a cutoff of TBN equal to 4 was used, our oil change intervals would have been set at 75 hours or less rather than at 250 hours during operation, with gas passing through the Winslow filter. It was also assumed that oil TBN level was an accurate way of predicting the oil's ability to counter the effects of acid accumulation in the oil. This assumption may be incorrect.

It should also be noted that a standard oil analysis, which includes a spectrographic analysis of wear metals and analytic measurements of some oil properties, should not be relied upon solely to predict developing problems. Wear metals were capable of predicting that damage was being done to the engine. However, that damage may have been initiated by acidic oil conditions prior to the appearance of unacceptable wear metal levels. The analytic properties including viscosity, percent water, antifreeze contamination, percent fuel dilution, solids accumulation, and varnish levels did not provide any indication of the existence of an acidic oil condition.

Reliance on a standard oil test analysis could provide one with a false sense of security until after the damage has already begun. Other analytical procedures are needed to predict the occurrence of acidic oil conditions.

From our experiences with biogas containing a relatively high level of hydrogen sulfide (3000 to 6000 ppm), three conclusions can be drawn. They are: (1) high TBN oils alone cannot be expected to counter the effects of acid accumulation in the oil; (2) the Winslow filter in combination with high TBN oils and medium length oil change intervals (250 hours) cannot counter the effects of acid accumulation in the oil; and (3) the effects of acid accumulation in the oil creates the greatest problems with but is not limited to components containing copper. Alternative materials for bearings, wrist pin inserts, and other components normally containing copper should be considered. The eventual solution to this problem may involve a combination of several different measures, some of which were used in this study.

This study also clearly illustrated the need of the cogenerator to include a well designed protection system to allow unattended operation. Our experience would indicate that it is highly desirable to protect the engine from operation under the following potential situations: (1) excessive engine coolant temperature; (2) low coolant level; (3) low oil pressure; (4) low oil level; (5) overspeed; (6) excessive vibration; and (7) low gas pressure. The generator and electrical system should also be protected from: (1) over current, and (2) reverse current flow.

The electrical utility may require additional desirable features for the electrical protection system such as over and under voltage and frequency limitations. The protection package for the cogenerator is not the place for cutting corners or reducing costs.

IV.D. FUTURE RESEARCH NEEDS

As a result of the experiences gained during this project, three questions remain that deserve additional attention. The most troubling concern relates to the ability to control the excessive wear related problems that occurred. Several potential alternatives offer promise that this problem can be corrected. They include different methods for treating or removing the sulfur in the fuel, alternative metals to copper for engine components, and different formulations of oil.

It may be impossible or too costly to completely eliminate the harmful effects of the hydrogen sulfide in the biogas. For this situation, it will be important to develop an understanding of accurate evaluation techniques that will assist in the decision of oil change intervals. Oil properties that will best predict undesirable acid buildup in the oil and its limits so that equipment suppliers and farmers can evaluate desirable oil change intervals remain to be identified.

Finally, additional consideration should be given to the design of the cogeneration heat recovery system and the digester heating system so that the quality of heat of the two systems is compatible. The 80° to 90°C hot water from a cogenerator appear to be compatible with our digester, but further testing is needed. Other alternatives such as direct injection of steam into the digester might also deserve consideration.

CHAPTER V

CONCLUSIONS

BACKGROUND

1. Cogeneration, i.e., the production of electricity and heat with an internal combustion engine, is a viable alternative for the use of biogas produced by anaerobic digestion. It is encouraged by existing laws (the national Public Utility Regulatory Act); and the hot water and electricity could supply large fractions of dairy farm energy needs.

2. Installation of cogeneration on U.S. dairies would be the equivalent of installing 1,000 megawatts of electric power generation capacity.

3. Methane has been described as an ideal engine fuel; it has been used in over 400,000 vehicles around the world, and it is presently used in engines powering over 5,000 megawatts of cogeneration capacity. The use of biogas with greater than 30 percent by volume carbon dioxide and additional contaminants in small farm scale cogenerators is limited. This study is one of the first to focus on small scale cogeneration with biogas.

4. Theoretical estimates of the economics of cogeneration reported total costs ranging from $0.009 to $0.115 per kWh, but these estimates assumed substantial engine lifetimes (11 years). This assumption contrasts with some estimates that have given engine lifetime estimates of less than one year for high speed internal combustion engines.

BIOGAS PRODUCTION

5. This study continued to document full scale anaerobic digestion of dairy manure during the fifth and sixth years of operation of digesters designed for approximately 65 cows. Parallel operation of a conventional completely mixed digester and a low-cost plug flow reactor continued to indicate that the plug flow unit was more efficient and more cost-effective than the completely mixed alternative. Biogas production rates in the plug flow reactor produced as much as 1 volume per volume per day greater than the completely mixed digester under parallel operating conditions. Higher loading rates tend to accentuate the difference, and hydraulic retention times longer than 30 days resulted in comparable results from both reactors.

6. No significant problems were observed with maintaining stable and continuous biogas production in either system. The plug flow reactor was much easier to operate, to correct small problems, or to modify for different operational conditions.

7. Two substantial changes in the physical characteristics of the full scale digesters were incorporated in an attempt to increase gas production. An improved design for the top and improved flexible material was used to increase the size of the plug flow reactor from 38 m^3 to 93.5 m^3. The increase in volume was done rapidly (within five weeks) and at a cost of less than \$40 per m^3. The new top system consisted of a concrete collar to which the flexible top was attached with a wet seal. This new design solved many of the structural and construction problems associated with the early low cost design.

8. Modifications to the plug flow reactor resulted in elimination of the effluent baffle, under which the digester slurry flowed in all previous studies. Tracer studies and subsequent performance indicated that short-circuiting was occurring in this system, and this was exaggerated by temperature differentials between the feed slurry and the digesting mass. It was concluded that the inclusion of an effluent baffle is a critical part of the plug flow design.

9. A review of the design alternatives for farm scale digesters indicated that inclusion of a preheating mixing unit could stabilize high rate animal waste digestion and simplify the reactor designs in order to test the feasibility of a series system composed of a completely mixed digester followed by a plug flow system. The 38 m^3 completely mixed reactor was repiped so that the effluent served as a feed for the plug flow unit. Hydraulic retention time in the first unit was 5.5 days when the plug flow digester was operating at an approximate 15-day hydraulic retention time. Although the heat capacity of the completely mixed digester was exceeded, the system was stable and able to produce large quantities of gas with the plug flow digester averaging nearly 2 volumes per volume per day.

BIOGAS TRANSMISSION AND STORAGE

10. Biogas transmission and storage were examined ranging from atmospheric pressure large volume storage through blowing of the biogas from the digester to the cogeneration system. Inclusion of the flexible "pillow tank" introduced a large amount of flexibility as well as a physical method of monitoring and managing the biogas. The system is recommended and should be considered for inclusion in most designs.

11. The largest number of mechanical problems and complications was caused by the use of intermediate pressure compressors and storage. It is doubtful that this technology can be economically attractive on small farm operations. However, the low pressure blowers were reliable and were useful for many different operations.

12. The contaminants in the biogas produced significant operational problems. Large quantities of condensed water

resulted in freezing accumulations during adverse weather. All of the gas piping and storage systems accumulated a black, grease-like substance in significant quantities. It was thought that this was related to the use of some metal pipes in the system and the interaction of hydrogen sulfides. It is anticipated that this material could cause problems with mechanical equipment and gas meters.

13. Average hydrogen sulfide levels ranged from 3,000 to 4,000 ppm in the biogas. This was expected to cause operational problems since this is much higher than the acceptable level of most engine operation. Some manufacturers recommend concentrations of less than 1,000 ppm for use in engine operation. Efforts were made to scrub the hydrogen sulfide in a portion of this test but were not successful. Filters were also purchased, but their effects on changing the total sulfur content of the biogas were not documented.

COGENERATION

14. A 25 kW capacity cogeneration system was developed with specifications agreed upon by the cogeneration unit's assembler, engine manufacturer, and the principal investigators. It was intended that this unit would operate in an intermittent mode (part of each day). In general, the engine was operated in this mode with run times ranging from 6 to 15 hours per day for a total of 2500 hours.

15. Smooth engine operation was primarily influenced by spark timing and fuel-air mixtures. In general, smooth engine operation on biogas was maintained over the 2500 hours of operation.

16. Ideal spark timing for operation of the engine on biogas was considerably advanced from those settings normally expected for more conventional gaseous fuels. The minimum spark timing for maximum power output ranged from 25° BTDC at 5 kW to 40° BTDC at 25 kW.

17. Smooth engine operation was noted for fuel-air equivalence ratios ($\emptyset$) between 0.78 and 1.3. The leanest possible setting for smooth operation was not checked during this study. Operation richer than $\emptyset = 1.3$ often caused missing and rough operation.

18. The induction generator proved to be a reliable and simple method of generating power in parallel with the utility. The speed versus load characteristics of the induction generator closely matched manufacturer data. Rated power was attained at 1837 R.P.M. However, power factor characteristics of the unit were below that suggested by the manufacturer. Addition of capacitance enabled correction of low power factor levels.

19. Maximum total energy recovery was 71 percent, with 26 percent of the biogas energy converted to electricity and 45 percent recovered as hot water.

20. Electrical energy efficiency of the cogenerator peaked at lean fuel-air mixtures (ϕ = 0.8 to 0.9) and near rated operation. Thermal energy efficiency peaked at lean fuel-air mixtures (ϕ = 0.8 to 1.0) and low loads. Combined electrical and thermal energy efficiency peaked at lean fuel-air mixtures but remained generally constant for all loads.

21. Where electricity is the product of greatest value, it is suggested that the cogeneration unit be operated at 60% or more of rated power and at lean fuel-air mixtures (ϕ = 0.8 to 0.9). Sizing of the cogeneration unit and procedures for identifying and maintaining desired fuel-air mixtures will be critical to the cost effective use of cogeneration.

22. Throughout the operations of the cogeneration unit, the frequent observations of the buffering capacity of the oil as reflected by the total base number (TBN) was relied upon to indicate the need for oil changers. It was assumed that the oil would absorb most of the acid contaminants and minimize wear on the engine. This was done in cooperation with an oil company. When operating with raw biogas and with oil with a high TBN of 10, the TBN rating dropped to the minimum acceptable level of 2 within 55 hours of operation. The oil was changed at this time.

23. Raw biogas produced rapid deterioration of internal engine components containing copper (i.e., bearings and wrist pins). Attempts to use high TBN oils and moderate to short length oil change intervals did not sufficiently protect the engine.

24. Biogas scrubbed by a Winslow gas conditioner for removing mercaptans in conjunction with high TBN oils and moderate length oil change intervals did not satisfactorily protect the engine from wear of internal engine components containing copper.

25. The cogeneration engine failed twice during this study, once early in the operation and after 2500 hours of operation. The first failure resulted from severe overheating, and the second was a rod bearing failure. The reasons for both of these were poorly identified; however, it appears that the first failure resulted from a combination of inadequately monitored equipment (insufficient low coolant alarms and inadequate waste heat dump system) and the method of operation. The second failure appeared to be a result of accelerated wear of engine bearings due to contaminants in the biogas.

26. Before biogas utilization in an internal combustion engine becomes a viable technology, procedures for biogas contaminant removal and/or easy prediction of undesirable acidic oil conditions and/or better methods of resisting acid accumulation in the oil must be identified.

27. Due to the high number of hours of unattended engine operation, it is critical that the cogeneration unit include a well designed protection package of controls. Our experience clearly demonstrated the need to protect the unit from excessive engine vibration, high coolant temperatures, low coolant levels, low oil pressure and level, low gas pressure, engine overspeed and generator overcurrent and reverse current flow. The electrical protection package may require additional features not utilized in this system.

28. Due to unattended operation and variable heating loads and demands, it is essential that the system be designed with heat wasting capabilities equal to the cogenerator's heat production potential. This should also be accompanied by redundant monitors and heat wasting methods.

29. The location of the electrical equipment and the cogeneration system appeared to be much more critical than would be expected. The presence of sulfur-based gases in the general atmosphere caused significant corrosion of all copper piping and electrical contacts and to our radiator with copper fins. The cogenerator should be kept in well ventilated areas.

30. This study shows a wide range of potentials for cogeneration at farm scale. It also emphasizes the lack of reliable systems or methods for minimizing the effects of constituents within the biogas on the engine. It is recommended that additional documentation of the several hundred units that are presently installed be documented to expand our knowledge of biogas use in cogeneration.

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APPENDIX A

PLUG FLOW AND COMPLETELY MIXED DIGESTER OPERATION SUMMARY

The full scale plug flow digester was operated from June 2, 1978 to June 14, 1983, a period of 1839 days. The completely mixed digester was operated from April 27, 1978 to June 14, 1983, a period of 1875 days. In this appendix, digester operation is summarized at time intervals of approximately one week over the period December 1, 1980 to June 14, 1983. Table A-1 summarizes the operation of the completely mixed digester. Table A-2 summarizes the plug flow digester operation while at a reactor volume of 40 m^3. Table A-3 summarizes the plug flow digester operation during the series operation mode of the study.

TABLE A-1. WEEKLY SUMMARY OF THE PERFORMANCE OF THE COMPLETELY MIXED DIGESTER.

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
01-Dec-80	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
07-Dec-80	26.0	NA	36.1	62.0	0.6	NA	NA	NA	NA	NA	NA
14-Dec-80	35.0	NA	51.4	66.0	1.9	NA	NA	NA	NA	NA	NA
21-Dec-80	35.0	NA	43.5	62.0	2.0	NA	NA	NA	NA	NA	NA
28-Dec-80	37.0	10.0	35.3	61.0	1.3	NA	NA	NA	NA	NA	NA
04-Jan-81	32.0	8.0	21.8	62.0	1.3	NA	NA	NA	NA	NA	NA
11-Jan-81	26.0	8.0	32.3	70.0	1.3	NA	NA	NA	NA	NA	NA
18-Jan-81	34.0	4.0	57.8	62.0	1.7	NA	NA	NA	NA	NA	NA
25-Jan-81	36.0	NA	78.0	NA	2.6	NA	NA	NA	NA	NA	NA
01-Feb-81	36.0	6.0	75.6	58.0	2.4	12.1	89.0	NA	7.9	NA	NA
08-Feb-81	37.0	8.0	57.4	59.0	1.2	10.9	88.7	NA	8.0	84.0	NA
15-Feb-81	36.0	7.0	70.0	52.0	2.3	11.6	88.6	NA	7.6	84.6	NA
22-Feb-81	34.0	6.0	60.6	60.0	3.5	NA	NA	NA	7.0	83.7	7.5
01-Mar-81	35.0	8.0	62.2	62.0	1.7	10.2	89.2	7.0	8.1	82.8	NA
08-Mar-81	33.0	7.0	33.1	60.0	3.8	12.2	90.3	6.8	7.5	84.6	7.4
15-Mar-81	31.0	7.0	47.3	55.0	2.2	12.3	90.0	NA	8.3	83.9	
20-Mar-81	32.0	7.0	63.0	60.0	NA	10.5	89.2	NA	8.1	85.9	
30-Mar-81	NA	NA	NA	NA	NA	NA	NA	NA	NA	85.3	
06-Apr-81	24.0	7.0	41.6	62.0	NA	10.6	89.2	NA	NA	NA	
14-Apr-81	33.0	8.0	49.7	62.0	2.3	NA	NA	NA	NA	NA	
06-Jul-81	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
13-Jul-81	32.0	NA	44.9	NA	2.0	NA	NA	NA	NA	NA	
20-Jul-81	33.0	NA	37.2	NA	0.7	NA	NA	NA	NA	NA	
26-Jul-81	34.0	NA	57.1	NA	2.5	NA	NA	NA	NA	NA	
02-Aug-81	29.0	NA	73.2	NA	4.1	NA	NA	NA	NA	NA	
09-Aug-81	32.0	NA	58.2	NA	1.4	NA	NA	NA	NA	NA	
16-Aug-81	31.0	NA	56.5	NA	2.6	NA	NA	NA	NA	NA	
23-Aug-81	30.0	18.0	66.8	NA	3.5	NA	NA	NA	NA	NA	
30-Aug-81	29.0	19.0	63.1	NA	2.2	NA	NA	NA	NA	NA	
06-Sep-81	30.0	19.0	61.8	NA	1.8	NA	NA	NA	NA	NA	
13-Sep-81	34.0	NA	49.1	NA	0.6	NA	NA	NA	NA	NA	
20-Sep-81	38.0	17.0	54.6	64.0	1.0	10.4	88.9	6.5	8.1	84.8	
27-Sep-81	36.0	16.0	38.0	60.0	1.0	11.0	88.9	6.3	8.2	84.9	

TABLE A-1. WEEKLY SUMMARY OF THE PERFORMANCE OF THE COMPLETELY MIXED DIGESTER (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
04-Oct-81	39.0	16.0	25.5	52.0	0.5	10.9	88.2	6.4	7.7	85.1	7.6
11-Apr-81	42.0	15.0	22.1	70.0	1.0	10.6	88.9	6.5	7.6	85.0	7.5
18-Oct-81	31.0	NA	30.8	NA	1.6	NA	NA	NA	7.2	84.5	NA
25-Oct-81	28.0	NA	25.4	NA	0.2	NA	NA	NA	NA	NA	NA
01-Nov-81	30.0	13.0	21.9	NA	0.9	9.9	88.9	NA	7.8	85.7	NA
08-Nov-81	28.0	12.0	20.6	NA	0.9	9.8	88.0	NA	7.4	83.8	NA
15-Nov-81	28.0	11.0	32.3	NA	1.9	10.1	86.8	7.0	7.8	84.9	7.5
22-Nov-81	27.0	10.0	38.4	62.0	1.2	12.5	88.8	NA	NA	NA	NA
29-Nov-81	23.0	10.0	28.3	NA	1.0	11.8	88.0	6.7	9.0	85.6	7.6
06-Dec-81	24.0	10.0	37.9	NA	0.8	10.9	87.7	6.7	8.8	85.3	7.6
13-Dec-81	32.0	9.0	41.7	62.0	1.6	12.1	89.1	NA	9.0	84.9	NA
20-Dec-81	31.0	8.0	40.7	NA	1.7	NA	NA	NA	NA	NA	NA
27-Dec-81	31.0	7.0	34.8	NA	0.9	NA	NA	NA	NA	NA	NA
03-Jan-82	38.0	9.0	31.1	NA	0.7	NA	NA	NA	NA	NA	NA
10-Jan-82	35.0	9.0	38.0	NA	2.3	NA	NA	NA	NA	NA	NA
17-Jan-82	32.0	6.0	38.0	NA	1.4	10.9	85.3	NA	8.9	81.7	NA
24-Jan-82	28.0	7.0	24.3	62.0	3.0	10.8	86.8	NA	9.0	84.0	NA
31-Jan-82	26.0	4.0	16.2	NA	2.8	11.4	85.7	NA	9.4	83.5	NA
07-Feb-82	21.0	6.0	14.0	NA	0.4	NA	NA	NA	NA	NA	NA
14-Feb-82	24.0	7.0	20.4	60.0	0.6	NA	NA	NA	NA	NA	NA
21-Feb-82	26.0	9.0	32.0	NA	0.8	11.4	86.9	7.1	9.1	84.1	7.6
28-Feb-82	38.0	9.0	36.1	64.0	1.1	NA	NA	NA	NA	NA	NA
07-Mar-82	35.0	8.0	33.5	NA	2.6	NA	NA	NA	NA	NA	NA
14-Mar-82	34.0	9.0	35.7	NA	2.0	12.7	86.8	NA	8.9	83.0	NA
22-Nov-81	27.0	10.0	38.4	62.0	1.2	12.5	88.8	NA	NA	NA	NA
29-Nov-81	23.0	10.0	28.3	NA	1.0	11.8	88.0	6.7	9.0	85.6	7.6
06-Dec-81	24.0	10.0	37.9	NA	0.8	10.9	87.7	6.7	8.8	85.3	7.6
13-Dec-81	32.0	9.0	41.7	62.0	1.6	12.1	89.1	NA	9.0	84.9	NA
20-Dec-81	31.0	8.0	40.7	NA	1.7	NA	NA	NA	NA	NA	NA
27-Dec-81	31.0	7.0	34.8	NA	0.9	NA	NA	NA	NA	NA	NA
03-Jan-82	38.0	9.0	31.1	NA	0.7	NA	NA	NA	NA	NA	NA
10-Jan-82	35.0	9.0	38.0	NA	2.3	NA	NA	NA	NA	NA	NA
17-Jan-82	32.0	6.0	38.0	NA	1.4	10.9	85.3	NA	8.9	81.7	NA
24-Jan-82	28.0	7.0	24.3	62.0	3.0	10.8	86.8	NA	9.0	84.0	NA

TABLE A-1. WEEKLY SUMMARY OF THE PERFORMANCE OF THE COMPLETELY MIXED DIGESTER (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
31-Jan-82	26.0	4.0	16.2	NA	2.8	11.4	85.7	NA	9.4	83.5	NA
07-Feb-82	21.0	6.0	14.0	NA	0.4	NA	NA	NA	NA	NA	NA
14-Feb-82	24.0	7.0	20.4	60.0	0.6	NA	NA	NA	NA	NA	NA
21-Feb-82	26.0	9.0	32.0	NA	0.8	11.4	86.9	7.1	9.1	84.1	7.6
28-Feb-82	38.0	9.0	36.1	64.0	1.1	NA	NA	NA	NA	NA	NA
07-Mar-82	35.0	8.0	33.5	NA	2.6	NA	NA	NA	NA	NA	NA
14-Mar-82	34.0	9.0	35.7	NA	2.0	12.7	86.8	NA	8.9	83.0	NA
21-Mar-82	30.0	10.0	23.3	NA	0.6	NA	NA	NA	NA	NA	NA
28-Mar-82	33.0	7.0	31.1	NA	1.7	NA	NA	NA	8.7	83.6	7.8
04-Apr-82	40.0	7.0	32.0	NA	1.6	11.3	86.9	7.1	8.5	82.7	7.7
11-Apr-82	33.0	7.0	26.0	NA	0.5	NA	NA	NA	NA	NA	NA
18-Apr-82	33.0	7.0	17.4	NA	NA	NA	NA	NA	NA	NA	NA
25-Apr-82	28.0	8.0	12.6	NA	0.5	NA	NA	NA	NA	NA	NA
02-May-82	32.0	8.0	10.9	NA	0.3	NA	NA	NA	NA	NA	NA
09-May-82	35.0	9.0	19.0	NA	0.8	10.0	86.9	6.9	8.0	83.4	7.9
16-May-82	34.0	10.0	21.4	NA	1.0	12.1	87.0	6.9	7.9	83.1	7.8
23-May-82	33.0	12.0	32.3	NA	1.6	12.1	87.7	6.8	8.4	83.0	7.9
30-May-82	32.0	13.0	32.5	NA	1.6	11.7	86.6	6.6	8.9	83.9	7.8
06-Jun-82	33.0	14.0	37.1	NA	2.0	12.0	88.2	6.7	9.5	84.6	7.8
13-Jun-82	30.0	14.0	29.1	NA	1.6	13.0	88.8	6.5	9.0	85.0	7.8
20-Jun-82	29.0	14.0	10.9	NA	NA	11.9	86.0	6.5	NA	NA	NA
25-Jun-82	30.0	16.0	21.7	NA	1.1	NA	NA	NA	NA	NA	NA
08-Jul-82	37.0	17.0	32.3	NA	0.8	10.5	87.6	6.5	8.5	84.6	7.6
15-Jul-82	41.0	20.0	25.9	NA	0.7	10.8	87.4	6.7	8.5	83.9	NA
20-Jul-82	43.0	21.0	21.5	NA	NA	NA	NA	NA	NA	NA	NA
28-Aug-82	39.0	20.0	22.1	NA	0.1	11.5	88.6	6.4	7.5	82.9	7.7
04-Sep-82	32.0	18.0	22.1	NA	0.1	12.7	89.5	6.5	8.2	84.0	7.6
11-Sep-82	35.0	18.0	27.6	NA	0.1	11.6	89.3	6.4	7.7	83.8	7.6
18-Sep-82	35.0	18.0	46.1	NA	3.3	11.2	89.3	6.5	8.9	85.5	7.6
25-Sep-82	34.0	18.0	57.4	NA	3.4	11.2	88.8	6.5	8.9	86.5	7.6
02-Oct-82	34.0	17.0	66.3	NA	2.7	10.8	88.5	6.5	8.6	86.7	7.6
13-Oct-82	36.0	18.0	62.5	NA	2.8	12.5	89.3	6.4	8.8	86.3	7.6
31-Oct-82	30.0	NA	24.4	NA	NA	NA	NA	NA	NA	NA	NA
07-Nov-82	36.0	10.0	47.3	NA	2.1	NA	NA	NA	NA	NA	NA

TABLE A-1. WEEKLY SUMMARY OF THE PERFORMANCE OF THE COMPLETELY MIXED DIGESTER (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
14-Nov-82	34.0	10.0	24.7	NA	0.6	11.3	87.6	6.8	8.5	85.2	7.6
21-Nov-82	32.0	10.0	25.1	NA	0.8	11.8	88.3	6.9	8.0	83.9	7.5
28-Nov-82	30.0	9.0	23.0	NA	1.0	12.3	87.9	6.8	8.0	83.7	7.6
05-Dec-82	31.0	10.0	26.7	NA	1.2	10.8	87.3	7.2	8.7	84.2	7.6
12-Dec-82	31.0	10.0	27.1	NA	1.1	10.6	87.1	7.0	8.4	82.0	8.0
19-Dec-82	32.0	9.0	16.6	NA	0.2	12.7	87.7	7.0	8.6	83.8	7.8
26-Dec-82	31.0	8.0	24.7	NA	1.1	10.6	87.2	6.8	8.4	83.6	7.8
02-Jan-83	33.0	8.0	29.2	NA	1.1	11.0	87.4	6.8	8.3	83.4	7.8
09-Jan-83	33.0	8.0	30.3	NA	1.0	11.6	87.9	6.8	8.3	83.8	7.8
16-Jan-83	37.0	7.0	31.5	NA	0.6	12.4	89.2	6.9	8.3	82.6	7.7
23-Jan-83	34.0	6.0	39.2	NA	1.8	11.9	88.9	7.2	8.3	83.0	7.7
06-Feb-83	33.0	6.0	30.7	NA	1.1	12.2	88.6	6.9	8.8	83.6	7.7
13-Feb-83	35.0	5.0	42.0	NA	1.6	11.6	88.1	6.8	8.6	83.9	7.7
20-Feb-83	30.0	5.0	32.3	NA	6.7	12.0	87.5	6.9	9.6	85.3	7.6
27-Feb-83	27.0	5.0	18.2	NA	6.3	11.0	87.0	7.2	10.6	86.4	7.2
06-Mar-83	28.0	3.0	14.2	30.0	6.7	11.6	87.2	7.3	10.7	87.0	7.0
13-Mar-83	24.0	4.0	21.1	NA	5.6	10.6	86.7	7.4	11.3	87.1	7.0
20-Mar-83	27.0	5.0	17.0	NA	6.6	13.0	88.6	7.0	11.2	87.0	7.0
27-Mar-83	26.0	6.0	13.8	NA	6.2	12.4	87.7	6.8	11.1	87.2	6.9
03-Apr-83	23.0	5.0	12.5	NA	5.3	12.2	88.0	7.1	11.4	87.3	6.9
10-Apr-83	21.0	5.0	14.2	NA	5.8	11.2	88.0	7.0	11.3	87.6	6.9
17-Apr-83	21.0	5.0	10.9	NA	7.4	11.6	87.8	7.0	11.5	88.0	6.9
24-Apr-83	17.0	5.0	8.1	NA	6.1	NA	NA	NA	NA	NA	NA
01-May-83	20.0	7.0	10.5	NA	7.1	NA	NA	NA	NA	NA	NA
08-May-83	23.0	9.0	14.2	NA	7.2	10.2	87.7	7.0	10.6	87.7	6.7
15-May-83	23.0	9.0	10.5	NA	5.3	NA	NA	NA	NA	NA	NA
20-May-83	24.0	NA	9.1	NA	5.6	NA	NA	NA	NA	NA	NA
13-Jun-83	23.0	11.0	9.6	NA	6.1	NA	NA	NA	NA	NA	NA

TABLE A-2. WEEKLY SUMMARY OF THE PERFORMANCE OF THE PLUG FLOW DIGESTER AT A REACTOR VOLUME OF 40 m^3.

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
01-Dec-80	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
07-Dec-80	32.0	NA	76.8	64.0	1.6	NA	NA	NA	NA	NA	NA
14-Dec-80	36.0	NA	83.3	65.0	2.5	NA	NA	NA	NA	NA	NA
21-Dec-80	29.0	NA	42.8	60.0	3.1	NA	NA	NA	NA	NA	NA
28-Dec-80	27.0	10.0	48.1	63.0	1.0	NA	NA	NA	NA	NA	NA
04-Jan-81	22.0	8.0	25.3	65.0	1.1	NA	NA	NA	NA	NA	NA
11-Jan-81	30.0	8.0	69.1	NA	0.9	NA	NA	NA	NA	NA	NA
18-Jan-81	35.0	4.0	91.8	63.0	3.8	NA	NA	NA	NA	NA	NA
25-Jan-81	35.0	NA	82.1	NA	2.4	NA	NA	NA	NA	NA	NA
01-Feb-81	32.0	6.0	91.8	62.0	2.7	12.1	89.0	NA	8.1	84.3	NA
08-Feb-81	30.0	8.0	67.5	62.0	3.2	10.9	88.7	NA	7.6	82.2	NA
15-Feb-81	36.0	7.0	107.9	60.0	2.6	11.6	88.6	NA	7.4	82.2	7.5
22-Feb-81	37.0	6.0	111.6	58.0	3.0	NA	NA	NA	6.9	80.0	NA
01-Mar-81	36.0	8.0	75.2	66.0	2.1	10.2	89.2	7.0	7.2	81.1	7.4
08-Mar-81	36.0	7.0	87.3	64.0	2.9	12.2	90.3	6.8	7.3	83.6	7.6
15-Mar-81	35.0	7.0	97.0	64.0	2.5	12.3	90.0	NA	6.9	82.9	NA
19-Mar-81	35.0	7.0	69.8	60.0	3.3	10.5	89.2	NA	6.8	81.4	NA
30-Mar-81	35.0	NA	35.2	NA	1.4	NA	NA	NA	NA	NA	NA
06-Apr-81	36.0	7.0	83.7	64.0	2.7	10.6	NA	NA	7.3	83.0	NA
11-Apr-81	35.0	15.0	35.1	64.0	1.2	10.6	88.9	6.5	7.2	85.0	7.5
14-Apr-81	33.0	8.0	61.0	66.0	1.7	NA	NA	NA	NA	NA	NA
06-Jul-81	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
13-Jul-81	36.0	NA	46.9	NA	2.0	NA	NA	NA	NA	NA	NA
20-Jul-81	37.0	NA	54.5	NA	1.5	NA	NA	NA	NA	NA	NA
26-Jul-81	34.0	NA	52.4	NA	2.1	NA	NA	NA	NA	NA	NA
02-Aug-81	33.0	NA	73.6	NA	3.2	NA	NA	NA	NA	NA	NA
09-Aug-81	35.0	NA	58.6	NA	1.7	NA	NA	NA	NA	NA	NA
16-Aug-81	34.0	NA	62.7	NA	2.7	NA	NA	NA	NA	NA	NA
23-Aug-81	34.0	18.0	94.6	NA	3.3	NA	NA	NA	NA	NA	NA
30-Aug-81	33.0	19.0	85.7	NA	2.2	NA	NA	NA	NA	NA	NA
06-Sep-81	32.0	19.0	72.9	NA	2.3	NA	NA	NA	NA	NA	NA
13-Sep-81	34.0	NA	50.8	NA	1.0	NA	NA	NA	NA	NA	NA
20-Sep-81	33.0	17.0	86.9	67.0	2.8	10.4	88.9	6.5	8.1	84.7	7.0
27-Sep-81	32.0	16.0	50.1	NA	0.7	11.0	88.9	6.3	8.4	85.3	7.2
04-Oct-81	30.0	16.0	50.2	60.0	1.2	10.9	88.2	6.4	7.6	85.5	7.5

TABLE A-2. WEEKLY SUMMARY OF THE PERFORMANCE OF THE PLUG FLOW DIGESTER AT A REACTOR VOLUME OF 40 m^3 (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
18-Oct-81	30.0	NA	55.5	NA	1.9	NA	NA	NA	NA	NA	NA
25-Oct-81	31.0	NA	27.1	NA	0.5	NA	NA	NA	NA	NA	NA
01-Nov-81	32.0	13.0	18.6	NA	0.8	9.9	88.9	NA	5.8	83.2	NA
08-Nov-81	28.0	12.0	27.5	NA	1.0	9.8	88.0	NA	6.6	83.7	NA
15-Nov-81	31.0	11.0	40.0	NA	1.7	10.1	86.8	NA	6.5	82.5	7.6
22-Nov-81	28.0	10.0	39.6	62.0	1.4	12.5	88.8	NA	NA	NA	NA
29-Nov-81	25.0	10.0	35.2	NA	1.2	11.8	NA	NA	7.6	83.8	7.5
06-Dec-81	28.0	10.0	35.5	NA	1.1	10.9	87.7	NA	7.5	83.9	7.5
13-Dec-81	26.0	9.0	23.8	62.0	2.0	12.1	89.1	NA	7.9	83.8	NA
20-Dec-81	29.0	8.0	26.5	NA	2.3	NA	NA	NA	NA	NA	NA
27-Dec-81	23.0	7.0	28.1	NA.	1.1	NA	NA	NA	NA	NA	NA
03-Jan-82	36.0	9.0	53.0	NA	1.4	NA	NA	NA	NA	NA	NA
10-Jan-82	37.0	9.0	27.6	NA	2.7	NA	NA	NA	NA	NA	NA
17-Jan-82	37.0	6.0	34.4	NA	2.3	10.9	85.3	NA	8.6	83.6	NA
24-Jan-82	37.0	7.0	35.6	62.0	3.2	10.8	86.8	NA	8.6	83.8	NA
31-Jan-82	28.0	4.0	31.6	NA	3.4	11.4	85.7	NA	9.1	82.8	NA
07-Feb-82	28.0	6.0	25.3	NA	1.8	NA	NA	NA	NA	NA	NA
14-Feb-82	26.0	7.0	22.1	NA	1.5	NA	NA	NA	NA	NA	NA
21-Feb-82	29.0	9.0	25.1	NA	0.8	11.4	86.9	7.1	8.6	83.5	7.6
28-Feb-82	35.0	9.0	35.8	NA	1.5	NA	NA	NA	NA	NA	NA
07-Mar-82	37.0	8.0	44.8	NA	2.9	NA	NA	NA	NA	NA	NA
14-Mar-82	33.0	9.0	37.8	62.0	1.8	12.7	86.8	NA	8.4	83.3	NA
21-Mar-82	32.0	10.0	42.9	60.0	1.9	NA	NA	NA	NA	NA	NA
28-Mar-82	40.0	7.0	58.7	66.0	1.1	NA	NA	NA	8.2	83.0	7.8
04-Apr-82	37.0	7.0	52.9	NA	2.1	11.3	86.9	7.1	7.7	82.1	7.8
11-Apr-82	36.0	7.0	35.3	NA	1.6	NA	NA	NA	NA	NA	NA
18-Apr-82	34.0	7.0	22.2	NA	0.0	NA	NA	NA	NA	NA	NA
25-Apr-82	35.0	8.0	33.5	NA	0.9	NA	NA	NA	NA	NA	NA
02-May-82	34.0	8.0	30.7	NA	1.4	NA	NA	NA	NA	NA	NA
09-May-82	36.0	9.0	40.8	NA	1.2	10.0	86.9	6.9	7.5	82.9	7.8
16-May-82	37.0	10.0	39.2	NA	0.7	12.1	87.0	6.9	7.9	83.3	7.8
23-May-82	37.0	12.0	50.5	NA	1.8	12.1	87.7	6.8	7.8	82.9	7.8
30-May-82	36.0	13.0	48.2	NA	2.1	11.7	86.6	6.6	7.9	82.7	7.8
06-Jun-82	36.0	14.0	40.0	NA	2.1	12.0	88.2	6.7	8.0	84.0	7.8
13-Jun-82	34.0	14.0	34.4	NA	1.5	13.0	88.8	6.5	8.0	84.2	7.8
20-Jun-82	34.0	14.0	21.0	NA	1.2	11.9	86.0	NA	7.2	83.7	7.8
25-Jun-82	29.0	16.0	12.7	NA	0.0	NA	NA	NA	NA	NA	NA

TABLE A-2. WEEKLY SUMMARY OF THE PERFORMANCE OF THE PLUG FLOW DIGESTER AT A REACTOR VOLUME OF 40 m^3 (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
18-Oct-81	30.0	NA	55.5	NA	1.9	NA	NA	NA	NA	NA	NA
25-Oct-81	31.0	NA	27.1	NA	0.5	NA	NA	NA	NA	NA	NA
01-Nov-81	32.0	13.0	18.6	NA	0.8	9.9	88.9	NA	5.8	83.2	NA
08-Nov-81	28.0	12.0	27.5	NA	1.0	9.8	88.0	NA	6.6	83.7	NA
15-Nov-81	31.0	11.0	40.0	NA	1.7	10.1	86.8	NA	6.5	82.5	7.6
22-Nov-81	28.0	10.0	39.6	62.0	1.4	12.5	88.8	NA	NA	NA	NA
29-Nov-81	25.0	10.0	35.2	NA	1.2	11.8	NA	NA	7.6	83.8	7.5
06-Dec-81	28.0	10.0	35.5	NA	1.1	10.9	87.7	NA	7.5	83.9	7.5
13-Dec-81	26.0	9.0	23.8	62.0	2.0	12.1	89.1	NA	7.9	83.8	NA
20-Dec-81	29.0	8.0	26.5	NA	2.3	NA	NA	NA	NA	NA	NA
27-Dec-81	23.0	7.0	28.1	NA	1.1	NA	NA	NA	NA	NA	NA
03-Jan-82	36.0	9.0	53.0	NA	1.4	NA	NA	NA	NA	NA	NA
10-Jan-82	37.0	9.0	27.6	NA	2.7	NA	NA	NA	NA	NA	NA
17-Jan-82	37.0	6.0	34.4	NA	2.3	10.9	85.3	NA	8.6	83.6	NA
24-Jan-82	37.0	7.0	35.6	62.0	3.2	10.8	86.8	NA	8.6	83.8	NA
31-Jan-82	28.0	4.0	31.6	NA	3.4	11.4	85.7	NA	9.1	82.8	NA
07-Feb-82	28.0	6.0	25.3	NA	1.8	NA	NA	NA	NA	NA	NA
14-Feb-82	26.0	7.0	22.1	NA	1.5	NA	NA	NA	NA	NA	NA
21-Feb-82	29.0	9.0	25.1	NA	0.8	11.4	86.9	7.1	8.6	83.5	7.6
28-Feb-82	35.0	9.0	35.8	NA	1.5	NA	NA	NA	NA	NA	NA
07-Mar-82	37.0	8.0	44.8	NA	2.9	NA	NA	NA	NA	NA	NA
14-Mar-82	33.0	9.0	37.8	62.0	1.8	12.7	86.8	NA	8.4	83.3	NA
21-Mar-82	32.0	10.0	42.9	60.0	1.9	NA	NA	NA	NA	NA	NA
28-Mar-82	40.0	7.0	58.7	66.0	1.1	NA	NA	NA	8.2	83.0	7.8
04-Apr-82	37.0	7.0	52.9	NA	2.1	11.3	86.9	7.1	7.7	82.1	7.8
11-Apr-82	36.0	7.0	35.3	NA	1.6	NA	NA	NA	NA	NA	NA
18-Apr-82	34.0	7.0	22.2	NA	0.0	NA	NA	NA	NA	NA	NA
25-Apr-82	35.0	8.0	33.5	NA	0.9	NA	NA	NA	NA	NA	NA
02-May-82	34.0	8.0	30.7	NA	1.4	NA	NA	NA	NA	NA	NA
09-May-82	36.0	9.0	40.8	NA	1.2	10.0	86.9	6.9	7.5	82.9	7.8
16-May-82	37.0	10.0	39.2	NA	0.7	12.1	87.0	6.9	7.9	83.3	7.8
23-May-82	37.0	12.0	50.5	NA	1.8	12.1	87.7	6.8	7.8	82.9	7.8
30-May-82	36.0	13.0	48.2	NA	2.1	11.7	86.6	6.6	7.9	82.7	7.8
06-Jun-82	36.0	14.0	40.0	NA	2.1	12.0	88.2	6.7	8.0	84.0	7.8
13-Jun-82	34.0	14.0	34.4	NA	1.5	13.0	88.8	6.5	8.0	84.2	7.8
20-Jun-82	34.0	14.0	21.0	NA	1.2	11.9	86.0	NA	7.2	83.7	7.8
25-Jun-82	29.0	16.0	12.7	NA	0.0	NA	NA	NA	NA	NA	NA

TABLE A-3. WEEKLY SUMMARY OF THE OPERATION OF THE PLUG FLOW DIGESTER AT A REACTOR VOLUME OF 93.5 m^3 (Cont.)

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
15-Jul-82	37.0	20.0	165.8	NA	5.6	10.8	87.4	6.7	9.2	85.4	7.7
20-Jul-82	42.0	21.0	108.8	NA	0.5	NA	NA	NA	9.1	85.6	7.8
04-Sep-82	28.0	18.0	87.3	60.0	2.3	12.7	89.5	6.5	9.4	85.6	7.6
11-Sep-82	31.0	18.0	115.9	NA	0.1	11.6	89.3	6.4	NA	NA	NA
18-Sep-82	33.0	18.0	114.5	NA	3.6	11.2	89.3	6.5	10.1	86.3	7.5
25-Sep-82	34.0	18.0	130.6	NA	4.1	11.2	88.8	6.5	9.5	85.9	7.6
02-Oct-82	32.0	17.0	154.5	NA	5.8	10.8	88.5	6.5	9.0	86.0	7.6
13-Oct-82	36.0	18.0	171.9	NA	4.9	12.5	89.3	6.4	9.0	86.4	7.6
31-Oct-82	29.0	18.0	71.1	NA	1.2	NA	NA	NA	NA	NA	NA
07-Nov-82	36.0	10.0	124.7	NA	4.2	NA	NA	NA	NA	NA	NA
14-Nov-82	35.0	10.0	101.9	NA	3.5	11.3	87.6	6.8	8.5	85.8	7.6
21-Nov-82	33.0	10.0	111.6	NA	5.1	11.8	88.3	6.9	8.4	83.9	7.7
28-Nov-82	30.0	9.0	89.3	NA	3.7	12.3	87.9	6.8	8.7	84.9	7.9
05-Dec-82	34.0	10.0	112.8	60.0	3.9	10.8	87.3	7.2	9.1	85.3	7.7
12-Dec-82	33.0	10.0	103.9	60.0	4.0	10.6	87.1	7.0	8.9	84.2	7.9
19-Dec-82	35.0	9.0	127.8	NA	5.0	12.7	87.7	7.0	9.6	85.0	7.5
26-Dec-82	33.0	8.0	122.1	NA	6.0	10.6	87.2	6.8	9.1	84.5	7.8
02-Jan-83	35.0	8.0	141.9	NA	7.4	11.0	87.4	6.8	9.3	84.8	7.8
09-Jan-83	38.0	8.0	140.0	NA	7.8	11.6	87.9	6.8	9.4	85.2	7.8
16-Jan-83	36.0	7.0	135.4	NA	5.3	12.4	89.2	6.9	9.6	85.7	7.7
23-Jan-83	38.0	6.0	143.5	NA	5.6	11.9	88.9	7.2	9.4	86.1	7.7
06-Feb-83	36.0	6.0	135.4	NA	4.7	12.2	88.6	6.9	9.6	84.8	7.8
13-Feb-83	34.0	5.0	145.2	NA	5.4	11.6	88.1	6.8	9.4	85.1	7.8

TABLE A-4. WEEKLY SUMMARY OF PLUG FLOW SERIES OPERATION.

DATE	REACTOR TEMP (°C)	FEED TEMP (°C)	BIOGAS (m^3/d)	METHANE (%)	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH
13-Feb-83	SERIES	OPERATION	BEGINS	NA	NA	NA	NA	NA	NA	NA	NA
20-Feb-83	36.0	5.0	127.3	NA	6.7	12.0	87.5	6.9	9.4	85.1	7.7
27-Feb-83	38.0	5.0	116.5	NA	6.3	11.0	87.0	7.2	9.2	84.6	7.7
06-Mar-83	39.0	3.0	142.7	NA	6.7	11.6	87.2	7.3	8.8	84.1	7.7
13-Mar-83	40.0	4.0	142.3	NA	5.6	10.6	86.7	7.4	8.7	84.1	7.7
20-Mar-83	41.0	5.0	172.6	NA	6.6	13.0	88.6	7.0	9.1	84.4	7.8
27-Mar-83	44.0	6.0	167.8	NA	6.2	12.4	87.7	6.8	9.0	84.3	7.8
03-Apr-83	46.0	5.0	126.1	NA	5.3	12.2	88.0	7.1	8.9	84.6	7.9
10-Apr-83	41.0	5.0	131.4	NA	5.8	11.2	88.0	7.0	9.3	85.4	7.8
17-Apr-83	42.0	5.0	203.3	NA	7.4	11.6	87.8	7.0	9.2	84.8	7.8
24-Apr-83	41.0	5.0	172.6	NA	6.1	NA	NA	NA	NA	NA	NA
01-May-83	38.0	7.0	150.8	NA	7.1	NA	NA	NA	NA	NA	NA
08-May-83	40.0	9.0	196.4	NA	7.2	10.2	87.7	7.0	9.8	86.3	7.7
15-May-83	41.0	9.0	162.1	NA	5.3	NA	NA	NA	NA	NA	NA
20-May-83	39.0	NA	149.4	NA	5.6	NA	NA	NA	NA	NA	NA
13-Jun-83	41.0	11.0	166.3	NA	6.1	NA	NA	NA	NA	NA	NA

APPENDIX B

PLUG FLOW AND COMPLETELY MIXED DIGESTER PERFORMANCE RESULTS

The results of the summaries of operation, presented in Appendix A were calculated at all points where data were available to produce the tables in this Appendix. Table B-1 summarizes the results of the plug flow digester operation at 40 m^3; Table B-2 summarizes its results at 93.5 m^3; and Table B-3 summarizes those of the completely mixed reactor.

TABLE B-1. PLUG FLOW DIGESTER PERFORMANCE RESULTS AT 40 m^3.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S REMOVAL RATE (g/ℓ/d)	T V S REMOVAL EFFICIENCY (%)	T V S REMOVAL GAS/TVS (ℓ/g)
01-Dec-80	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
01-Feb-81	2.7	12.1	89.0	NA	8.1	84.3	NA	14.8	2.30	7.27	2.66	36.59	0.86
08-Feb-81	3.2	10.9	88.7	NA	7.6	82.2	NA	12.5	1.69	7.73	2.74	35.38	0.62
15-Feb-81	2.6	11.6	88.6	NA	7.4	82.2	7.5	15.4	2.70	6.68	2.73	40.81	0.99
01-Mar-81	2.1	10.2	89.2	7.0	7.2	81.1	7.4	19.0	1.88	4.78	1.71	35.82	1.10
08-Mar-81	2.9	12.2	90.3	6.8	7.3	83.6	7.6	13.8	2.18	7.99	3.56	44.60	0.61
15-Mar-81	2.5	12.3	90.0	NA	6.9	82.9	NA	16.0	2.43	6.92	3.34	48.33	0.73
19-Mar-81	3.3	10.5	89.2	NA	6.8	81.4	NA	12.1	1.75	7.73	3.16	40.90	0.55
20-Sep-81	2.8	10.4	88.9	6.5	8.1	84.7	7.0	14.3	2.17	6.47	1.67	25.79	1.30
27-Sep-81	0.7	11.0	88.9	6.3	8.4	85.3	7.2	57.1	1.25	1.71	0.46	26.73	2.74
04-Oct-81	1.2	10.9	88.2	6.4	7.6	85.5	7.5	33.3	1.26	2.88	0.93	32.41	1.34
11-Oct-81	1.2	10.6	88.9	6.5	7.2	85.0	7.5	33.3	0.88	2.83	0.99	35.06	0.89
01-Nov-81	0.8	9.9	88.9	NA	5.8	83.2	NA	50.0		1.76	0.80	45.17	0.00
15-Nov-81	1.7	10.1	86.8	NA	6.5	82.5	7.6	4.0	1.00	14.25	ERR	ERR	ERR
06-Dec-81	1.1	10.9	87.7	NA	7.5	83.9	7.5	36.4	0.89	2.63	0.90	34.17	0.99
13-Dec-81	2.0	12.1	89.1	NA	7.9	83.8	NA	20.0	0.60	5.39	2.08	38.59	0.29
17-Jan-82	2.3	10.9	85.3	NA	8.6	83.6	NA	17.4	0.86	5.35	1.21	22.67	0.71
24-Jan-82	3.2	10.8	86.8	NA	8.6	83.8	NA	12.5	0.89	7.50	1.73	23.12	0.51
31-Jan-82	3.4	11.4	85.7	NA	9.1	82.8	NA	11.8	0.79	8.30	1.90	22.88	0.42
21-Feb-82	0.8	11.4	86.9	7.1	8.6	83.5	7.6	50.0	0.63	1.98	0.55	27.85	1.14
14-Mar-82	1.8	12.7	86.8	NA	8.4	83.3	NA	22.2	0.95	4.96	1.81	36.53	0.52
04-Apr-82	2.1	11.3	86.9	7.1	7.7	82.1	7.8	19.0	1.32	5.16	1.84	35.62	0.72
09-May-82	1.2	10.0	86.9	6.9	7.5	82.9	7.8	33.3	1.02	2.61	0.74	28.45	1.38
16-May-82	0.7	12.1	87.0	6.9	7.9	83.3	7.8	57.1	0.98	1.84	0.69	37.49	1.42
23-May-82	1.8	12.1	87.7	6.8	7.8	82.9	7.8	22.2	1.26	4.78	1.87	39.07	0.68
30-May-82	2.1	11.7	86.6	6.6	7.9	82.7	7.8	19.0	1.21	5.32	1.89	35.52	0.64
06-Jun-82	2.1	12.0	88.2	6.7	8.0	84.0	7.8	19.0	1.00	5.56	2.03	36.51	0.49
13-Jun-82	1.5	13.0	88.8	6.5	8.0	84.2	7.8	26.7	0.86	4.33	1.80	41.65	0.48
20-Jun-82	1.2	11.9	86.0	NA	7.2	83.7	7.8	3.4	0.53	3.07	NA	NA	NA
15-Jul-82	5.6	10.8	87.4	6.7	9.2	85.4	7.7	16.7	1.77	5.65	0.95	16.76	1.87

TABLE B-2. PLUG FLOW DIGESTER PERFORMANCE RESULTS AT 93.5 m^3.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S REMOVAL RATE (g/ℓ/d)	REMOVAL EFFICIENCY (%)	GAS/TVS (ℓ/g)
20-Jul-82	0.5	NA	NA	NA	9.1	85.6	7.8	187.0	1.16	NA	NA	NA	NA
04-Sep-82	2.3	12.7	89.5	6.5	9.4	85.6	7.6	40.7	0.93	2.80	0.82	29.21	1.14
18-Sep-82	3.6	11.2	89.3	6.5	10.1	86.3	7.5	26.0	1.22	3.85	0.49	12.85	2.47
25-Sep-82	4.1	11.2	88.8	6.5	9.5	85.9	7.6	22.8	1.40	4.36	0.78	17.95	1.78
02-Oct-82	5.8	10.8	88.5	6.5	9.0	86.0	7.6	16.1	1.65	5.93	1.13	19.02	1.47
13-Oct-82	4.9	12.5	89.3	6.4	9.0	86.4	7.6	19.1	1.84	5.85	1.77	30.34	1.04
14-Nov-82	3.5	11.3	87.6	6.8	8.5	85.8	7.6	26.7	1.09	3.71	0.98	26.32	1.12
21-Nov-82	5.1	11.8	88.3	6.9	8.4	83.9	7.7	18.3	1.19	5.68	1.84	32.36	0.65
28-Nov-82	3.7	12.3	87.9	6.8	8.7	84.9	7.9	25.3	0.96	4.28	1.36	31.68	0.70
05-Dec-82	3.9	10.8	87.3	7.2	9.1	85.3	7.7	24.0	1.21	3.93	0.69	17.67	1.74
12-Dec-82	4.0	10.6	87.1	7.0	8.9	84.2	7.9	23.4	1.11	3.95	0.74	18.83	1.49
19-Dec-82	5.0	12.7	87.7	7.0	9.6	85.0	7.5	18.7	1.37	5.96	1.59	26.74	0.86
26-Dec-82	6.0	10.6	87.2	6.8	9.1	84.5	7.8	15.6	1.31	5.93	1.00	16.81	1.31
02-Jan-83	7.4	11.0	87.4	6.8	9.3	84.8	7.8	12.6	1.52	7.61	1.37	17.97	1.11
09-Jan-83	7.8	11.6	87.9	6.8	9.4	85.2	7.8	12.0	1.50	8.51	1.82	21.45	0.82
16-Jan-83	5.3	12.4	89.2	6.9	9.6	85.7	7.7	17.6	1.45	6.27	1.61	25.62	0.90
23-Jan-83	5.6	11.9	88.9	7.2	9.4	86.1	7.7	16.7	1.53	6.34	1.49	23.50	1.03
06-Feb-83	4.7	12.2	88.6	6.9	9.6	84.8	7.8	19.9	1.45	5.43	1.34	24.69	1.08

TABLE B-3. COMPLETELY MIXED DIGESTER PERFORMANCE RESULTS.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S RATE (g/ℓ/d)	R E M O V A L EFFICIENCY (%)	GAS/TVS (ℓ/g)
01-Dec-80	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
08-Feb-81	1.2	10.9	88.7	NA	8.0	84.0	NA	29.5	1.62	3.28	1.00	30.49	1.62
15-Feb-81	2.3	11.6	88.6	NA	7.6	84.6	NA	15.4	1.98	6.68	2.50	37.44	0.79
01-Mar-81	1.7	10.2	89.2	7.0	8.1	82.8	NA	20.8	1.76	4.37	1.15	26.29	1.53
08-Mar-81	3.8	12.2	90.3	6.8	7.5	84.6	7.4	9.3	0.94	11.83	5.01	42.41	0.19
15-Mar-81	2.2	12.3	90.0	NA	8.3	83.9	7.5	16.1	1.34	6.88	2.55	37.09	0.52
20-Sep-81	1.0	10.4	88.9	6.5	8.1	84.8	7.0	35.4	1.54	2.61	0.67	25.71	2.30
27-Sep-81	1.0	11.0	88.9	6.3	8.2	84.9	7.4	35.4	1.07	2.76	0.80	28.81	1.35
04-Oct-81	0.5	10.9	88.2	6.4	7.7	85.1	7.6	70.8	0.72	1.36	0.43	31.84	1.67
11-Oct-81	1.0	10.6	88.9	6.5	7.6	85.0	7.5	35.4	0.62	2.66	0.84	31.45	0.75
01-Nov-81	0.9	9.9	88.9	NA	7.8	85.7	NA	39.3	0.62	2.24	0.54	24.05	1.15
08-Nov-81	0.9	9.8	88.0	NA	7.4	83.8	NA	39.3	0.58	2.19	0.62	28.09	0.94
15-Nov-81	1.9	10.1	86.8	7.0	7.8	84.9	7.5	18.6	0.91	4.71	1.15	24.46	0.79
29-Nov-81	1.0	11.8	88.0	6.7	9.0	85.6	7.6	35.4	0.80	2.93	0.76	25.81	1.06
06-Dec-81	0.8	10.9	87.7	6.7	8.8	85.3	7.6	44.3	1.07	2.16	0.46	21.48	2.31
13-Dec-81	1.6	12.1	89.1	NA	9.0	84.9	NA	22.1	1.18	4.87	1.42	29.13	0.83
17-Jan-82	1.4	10.9	85.3	NA	8.9	81.7	NA	25.3	1.07	3.68	0.80	21.79	1.34
21-Feb-82	0.8	11.4	86.9	7.1	9.1	84.1	7.6	44.3	0.90	2.24	0.51	22.75	1.78
14-Mar-82	2.0	12.7	86.8	NA	8.9	83.0	NA	17.7	1.01	6.23	2.05	32.99	0.49
04-Apr-82	1.6	11.3	86.9	7.1	8.5	82.7	7.7	22.1	0.90	4.44	1.26	28.41	0.72
09-May-82	0.8	10.0	86.9	6.9	8.0	83.4	7.9	44.3	0.54	1.96	0.46	23.22	1.18
16-May-82	1.0	12.1	87.0	6.9	7.9	83.1	7.8	35.4	0.60	2.97	1.12	37.64	0.54
23-May-82	1.6	12.1	87.7	6.8	8.4	83.0	7.9	22.1	0.91	4.80	1.65	34.30	0.55
30-May-82	1.6	11.7	86.6	6.6	8.9	83.9	7.8	22.1	0.92	4.58	1.20	26.30	0.76
13-Jun-82	1.6	13.0	88.8	6.5	9.0	85.0	7.8	22.1	0.82	5.22	1.76	33.73	0.47
08-Jul-82	0.8	10.5	87.6	6.5	8.5	84.6	7.6	44.3	0.91	2.08	0.45	21.82	2.01
15-Jul-82	0.7	10.8	87.4	6.7	8.5	83.9	NA	50.6	0.73	1.87	0.46	24.45	1.60
28-Aug-82	0.1	11.5	88.6	6.4	7.5	82.9	7.7	354.0	0.62	0.29	0.11	38.98	5.56
04-Sep-82	0.1	12.7	89.5	6.5	8.2	84.0	7.6	354.0	0.62	0.32	0.13	39.40	4.93
11-Sep-82	0.1	11.6	89.3	6.4	7.7	83.8	7.6	354.0	0.78	0.29	0.11	37.71	7.07
13-Oct-82	2.8	12.5	89.3	6.4	8.8	86.3	7.6	12.6	1.77	8.83	2.82	31.97	0.63
14-Nov-82	0.6	11.3	87.6	6.8	8.5	85.2	7.6	59.0	0.70	1.68	0.45	26.84	1.55
21-Nov-82	0.8	11.8	88.3	6.9	8.0	83.9	7.5	44.3	0.71	2.35	0.84	35.58	0.85
28-Nov-82	1.0	12.3	87.9	6.8	8.0	83.7	7.6	35.4	0.65	3.05	1.16	38.07	0.56

TABLE B-3. COMPLETELY MIXED DIGESTER PERFORMANCE RESULTS (Cont.)

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	TVS REMOVAL RATE (g/ℓ/d)	TVS REMOVAL EFFICIENCY (%)	TVS REMOVAL GAS/TVS (ℓ/g)
05-Dec-82	1.2	10.8	87.3	7.2	8.7	84.2	7.6	29.5	0.75	3.20	0.71	22.30	1.06
12-Dec-82	1.1	10.6	87.1	7.0	8.4	82.0	8.0	32.2	0.77	2.87	0.73	25.39	1.05
19-Dec-82	0.2	12.7	87.7	7.0	8.6	83.8	7.8	177.0	0.47	0.63	0.22	35.29	2.11
26-Dec-82	1.1	10.6	87.2	6.8	8.4	83.6	7.8	32.2	0.70	2.87	0.69	24.03	1.01
02-Jan-83	1.1	11.0	87.4	6.8	8.3	83.4	7.8	32.2	0.82	2.99	0.84	28.00	0.99
09-Jan-83	1.0	11.6	87.9	6.8	8.3	83.8	7.8	35.4	0.86	2.88	0.92	31.79	0.93
16-Jan-83	0.6	12.4	89.2	6.9	8.3	82.6	7.7	59.0	0.89	1.87	0.71	38.02	1.25
23-Jan-83	1.8	11.9	88.9	7.2	8.3	83.0	7.7	19.7	1.11	5.38	1.88	34.88	0.59
06-Feb-83	1.1	12.2	88.6	6.9	8.8	83.6	7.7	32.2	0.87	3.36	1.07	31.94	0.81
13-Feb-83	1.6	11.6	88.1	6.8	8.6	83.9	7.7	22.1	1.19	4.62	1.36	29.40	0.87
20-Feb-83	6.7	12.0	87.5	6.9	9.6	85.3	7.6	5.3	0.91	19.87	4.37	22.01	0.21
27-Feb-83	6.3	11.0	87.0	7.2	10.6	86.4	7.2	5.6	0.51	17.03	0.73	4.30	0.70
06-Mar-83	6.7	11.6	87.2	7.3	10.7	87.0	7.0	5.3	0.40	19.14	1.53	7.97	0.26
13-Mar-83	5.6	10.6	86.7	7.4	11.3	87.1	7.0	6.3	0.60	14.54	-1.04	-7.12	-0.58
20-Mar-83	6.6	13.0	88.6	7.0	11.2	87.0	7.0	5.4	0.48	21.47	3.31	15.40	0.15
27-Mar-83	6.2	12.4	87.7	6.8	11.1	87.2	6.9	5.7	0.39	19.05	2.09	10.99	0.19
03-Apr-83	5.3	12.2	88.0	7.1	11.4	87.3	6.9	6.7	0.35	16.07	1.17	7.30	0.30
10-Apr-83	5.8	11.2	88.0	7.0	11.3	87.6	6.9	6.1	0.40	16.15	-0.07	-0.43	-5.72
17-Apr-83	7.4	11.6	87.8	7.0	11.5	88.0	6.9	4.8	0.31	21.29	0.14	0.64	2.27
08-May-83	7.2	10.2	87.7	7.0	10.6	87.7	6.7	4.9	0.40	18.19	-0.71	-3.92	-0.56

APPENDIX C

PLUG FLOW AND COMPLETELY MIXED DIGESTER SUMMARY OF DATA POINT SELECTION

In this Appendix the data presented in Appendix B were grouped according to the total volatile solids organic loading rates (OLR) to form eight loading conditions for each digester. The eight loading conditions were formed by placing each data point calculated in Appendix B within the organic loading rate ranges listed below. Table C-1 illustrates the data points chosen for each plug flow reactor condition (P), while Table C-2 illustrates those of the completely mixed reactor (C).

CONDITION NUMBER	OLR RANGE (g TVS/ℓ-d) FROM	TO
C-1	0	1
C-2	1	2
C-3	2	3
C-4	3	4
C-5	4	5
C-6	5	6
C-7	6	7
C-8	8	22
P-1	1	2
P-2	2	3
P-3	3	4
P-4	4	5
P-5	5	6
P-6	6	7
P-7	7	8
P-8	8	10

TABLE C-1. SUMMARY OF THE PLUG FLOW DIGESTER LOADING CONDITION SELECTIONS.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	TVS REMOVAL RATE (g/ℓ/d)	TVS REMOVAL EFFICIENCY (%)	TVS REMOVAL GAS/TVS (ℓ/g)
PLUG FLOW CONDITION P-1													
27-Sep-81	0.7	11.0	88.9	6.3	8.4	85.3	7.2	57.1	1.25	1.71	0.46	26.73	2.74
01-Nov-81	0.8	9.9	88.9	NA	5.8	83.2	NA	50.0	0.47	1.76	0.80	45.17	0.00
21-Feb-82	0.8	11.4	86.9	7.1	8.6	83.5	7.6	50.0	0.63	1.98	0.55	27.85	1.14
16-May-82	0.7	12.1	87.0	6.9	7.9	83.3	7.8	57.1	0.98	1.84	0.69	37.49	1.42
PLUG FLOW CONDITION P-2													
04-Oct-81	1.2	10.9	88.2	6.4	7.6	85.5	7.5	33.3	1.26	2.88	0.93	32.41	1.34
11-Oct-81	1.2	10.6	88.9	6.5	7.2	85.0	7.5	33.3	0.88	2.83	0.99	35.06	0.89
06-Dec-81	1.1	10.9	87.7	NA	7.5	83.9	7.5	36.4	0.89	2.63	0.90	34.17	0.99
09-May-82	1.2	10.0	86.9	6.9	7.5	82.9	7.8	33.3	1.02	2.61	0.74	28.45	1.38
PLUG FLOW CONDITION P-3													
15-Nov-81	1.7	10.1	86.8	NA	6.5	82.5	7.6	4.0	1.00	3.73	1.06	28.48	0.94
20-Jun-82	1.2	11.9	86.0	NA	7.2	83.7	7.8	3.4	0.53	3.07	1.26	41.11	0.42
PLUG FLOW CONDITION P-4													
01-Mar-81	2.1	10.2	89.2	7.0	7.2	81.1	7.4	19.0	1.88	4.78	1.71	35.82	1.10
15-Mar-81	2.5	12.3	90.0	NA	6.9	82.9	NA	16.0	2.43	6.92	3.34	48.33	0.73
23-May-82	1.8	12.1	87.7	6.8	7.8	82.9	7.8	22.2	1.26	4.78	1.87	39.07	0.68
13-Jun-82	1.5	13.0	88.8	6.5	8.0	84.2	7.8	26.7	0.86	4.33	1.80	41.65	0.48
PLUG FLOW CONDITION P-5													
13-Dec-81	2.0	12.1	89.1	NA	7.9	83.8	NA	20.0	0.60	5.39	2.08	38.59	0.29
17-Jan-82	2.3	10.9	85.3	NA	8.6	83.6	NA	17.4	0.86	5.35	1.21	22.67	0.71
04-Apr-82	2.1	11.3	86.9	7.1	7.7	82.1	7.8	19.0	1.32	5.16	1.84	35.62	0.72
30-May-82	2.1	11.7	86.6	6.6	7.9	82.7	7.8	19.0	1.21	5.32	1.89	35.52	0.64
06-Jun-82	2.1	12.0	88.2	6.7	8.0	84.0	7.8	19.0	1.00	5.56	2.03	36.51	0.49

TABLE C-1. SUMMARY OF THE PLUG FLOW DIGESTER LOADING CONDITION SELECTIONS (Cont.)

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	TVS REMOVAL RATE (g/ℓ/d)	TVS REMOVAL EFFICIENCY (%)	GAS/TVS (ℓ/g)
PLUG FLOW CONDITION P-6													
15-Feb-81	2.6	11.6	88.6	NA	7.4	82.2	7.5	15.4	2.70	6.68	2.73	40.81	0.99
15-Mar-81	2.5	12.3	90.0	NA	6.9	82.9	NA	16.0	2.43	6.92	3.34	48.33	0.73
PLUG FLOW CONDITION P-7													
01-Feb-81	2.7	12.1	89.0	NA	8.1	84.3	NA	14.8	2.30	7.27	2.66	36.59	0.86
08-Feb-81	3.2	10.9	88.7	NA	7.6	82.2	NA	12.5	1.69	7.73	2.74	35.38	0.62
08-Mar-81	2.9	12.2	90.3	6.8	7.3	83.6	7.6	13.8	2.18	7.99	3.56	44.60	0.61
19-Mar-81	3.3	10.5	89.2	NA	6.8	81.4	NA	12.1	1.75	7.73	3.16	40.90	0.55
20-Sep-81	2.8	10.4	88.9	6.5	8.1	84.7	7.0	14.3	2.17	6.47	1.67	25.79	1.30
PLUG FLOW CONDITION P-8													
24-Jan-82	3.2	10.8	86.8	NA	8.6	83.8	NA	12.5	0.89	7.50	1.73	23.12	0.51
31-Jan-82	3.4	11.4	85.7	NA	9.1	82.8	NA	11.8	0.79	8.30	1.90	22.88	0.42

TABLE C-2. SUMMARY OF THE COMPLETELY MIXED DIGESTER LOADING CONDITION SELECTIONS.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S R E M O V A L RATE (g/ℓ/d)	EFFICIENCY (%)	GAS/TVS (ℓ/g)
COMPLETELY MIXED CONDITION C-1													
28-Aug-82	0.1	11.5	88.6	6.4	7.5	82.9	7.7	354.0	0.62	0.29	0.11	38.98	5.56
4-Sep-82	0.1	12.7	89.5	6.5	8.2	84.0	7.6	354.0	0.62	0.32	0.13	39.40	4.93
11-Sep-82	0.1	11.6	89.3	6.4	7.7	83.8	7.6	354.0	0.78	0.29	0.11	37.71	7.07
19-Dec-82	0.2	12.7	87.7	7.0	8.6	83.8	7.8	177.0	0.47	0.63	0.22	35.29	2.11
COMPLETELY MIXED CONDITION C-2													
04-Oct-81	0.5	10.9	88.2	6.4	7.7	85.1	7.6	70.8	0.72	1.36	0.43	31.84	1.67
09-May-82	0.8	10.0	86.9	6.9	8.0	83.4	7.9	44.3	0.54	1.96	0.46	23.22	1.18
15-Jul-82	0.7	10.8	87.4	6.7	8.5	83.9	NA	50.6	0.73	1.87	0.46	24.45	1.60
16-Jan-83	0.6	12.4	89.2	6.9	8.3	82.6	7.7	59.0	0.89	1.87	0.71	38.02	1.25
COMPLETELY MIXED CONDITION C-3													
20-Sep-81	1.0	10.4	88.9	6.5	8.1	84.8	7.0	35.4	1.54	2.61	0.67	25.71	2.30
27-Sep-81	1.0	11.0	88.9	6.3	8.2	84.9	7.4	35.4	1.07	2.76	0.80	28.81	1.35
11-Oct-81	1.0	10.6	88.9	6.5	7.6	85.0	7.5	35.4	0.62	2.66	0.84	31.45	0.75
01-Nov-81	0.9	9.9	88.9	NA	7.8	85.7	NA	39.3	0.62	2.24	0.54	24.05	1.15
08-Nov-81	0.9	9.8	88.0	NA	7.4	83.8	NA	39.3	0.58	2.19	0.62	28.09	0.94
29-Nov-81	1.0	11.8	88.0	6.7	9.0	85.6	7.6	35.4	0.80	2.93	0.76	25.81	1.06
06-Dec-81	0.8	10.9	87.7	6.7	8.8	85.3	7.6	44.3	1.07	2.16	0.46	21.48	2.31
21-Feb-82	0.8	11.4	86.9	7.1	9.1	84.1	7.6	44.3	0.90	2.24	0.51	22.75	1.78
16-May-82	1.0	12.1	87.0	6.9	7.9	83.1	7.8	35.4	0.60	2.97	1.12	37.64	0.54
08-Jul-82	0.8	10.5	87.6	6.5	8.5	84.6	7.6	44.3	0.91	2.08	0.45	21.82	2.01
21-Nov-82	0.8	11.8	88.3	6.9	8.0	83.9	7.5	44.3	0.71	2.35	0.84	35.58	0.85
12-Dec-82	1.1	10.6	87.1	7.0	8.4	82.0	8.0	32.2	0.77	2.87	0.73	25.39	1.05
02-Jan-83	1.1	11.0	87.4	6.8	8.3	83.4	7.8	32.2	0.82	2.99	0.84	28.00	0.99
09-Jan-83	1.0	11.6	87.9	6.8	8.3	83.8	7.8	35.4	0.86	2.88	0.92	31.79	0.93
COMPLETELY MIXED CONDITION C-4													
08-Feb-81	1.2	10.9	88.7	NA	8.0	84.0	NA	29.5	1.62	3.28	1.00	30.49	1.62
17-Jan-82	1.4	10.9	85.3	NA	8.9	81.7	NA	25.3	1.07	3.68	0.80	21.79	1.34
28-Nov-82	1.0	12.3	87.9	6.8	8.0	83.7	7.6	35.4	0.65	3.05	1.16	38.07	0.56
05-Dec-82	1.2	10.8	87.3	7.2	8.7	84.2	7.6	29.5	0.75	3.20	0.71	22.30	1.06
06-Feb-83	1.1	12.2	88.6	6.9	8.8	83.6	7.7	32.2	0.87	3.36	1.07	31.94	0.81

TABLE C-2. SUMMARY OF THE COMPLETELY MIXED DIGESTER LOADING CONDITION SELECTIONS (Cont.)

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	TVS REMOVAL RATE (g/ℓ/d)	TVS REMOVAL EFFICIENCY (%)	GAS/TVS (ℓ/g)
COMPLETELY MIXED CONDITION C-5													
01-Mar-81	1.7	10.2	89.2	7.0	8.1	82.8	NA	20.8	1.76	4.37	1.15	26.29	1.53
13-Dec-81	1.6	12.1	89.1	NA	9.0	84.9	NA	22.1	1.18	4.87	1.42	29.13	0.83
04-Apr-82	1.6	11.3	86.9	7.1	8.5	82.7	7.7	22.1	0.90	4.44	1.26	28.41	0.72
23-May-82	1.6	12.1	87.7	6.8	8.4	83.0	7.9	22.1	0.91	4.80	1.65	34.30	0.55
30-May-82	1.6	11.7	86.6	6.6	8.9	83.9	7.8	22.1	0.92	4.58	1.20	26.30	0.76
13-Feb-83	1.6	11.6	88.1	6.8	8.6	83.9	7.7	22.1	1.19	4.62	1.36	29.40	0.87
COMPLETELY MIXED CONDITION C-6													
13-Jun-82	1.6	13.0	88.8	6.5	9.0	85.0	7.8	22.1	0.82	5.22	1.76	33.73	0.47
23-Jan-83	1.8	11.9	88.9	7.2	8.3	83.0	7.7	19.7	1.11	5.38	1.88	34.88	0.59
COMPLETELY MIXED CONDITION C-7													
15-Feb-81	2.3	11.6	88.6	NA	7.6	84.6	NA	15.4	1.98	6.68	2.50	37.44	0.79
15-Mar-81	2.2	12.3	90.0	NA	8.3	83.9	7.5	16.1	1.34	6.88	2.55	37.09	0.52
14-Mar-82	2.0	12.7	86.8	NA	8.9	83.0	NA	17.7	1.01	6.23	2.05	32.99	0.49
COMPLETELY MIXED CONDITION C-8													
08-Mar-81	3.8	12.2	90.3	6.8	7.5	84.6	7.4	9.3	0.94	11.83	5.01	42.41	0.19
13-Oct-82	2.8	12.5	89.3	6.4	8.8	86.3	7.6	12.6	1.77	8.83	2.82	31.97	0.63
20-Feb-83	6.7	12.0	87.5	6.9	9.6	85.3	7.6	5.3	0.91	19.87	4.37	22.01	0.21
27-Feb-83	6.3	11.0	87.0	7.2	10.6	86.4	7.2	5.6	0.51	17.03	0.73	4.30	0.70
06-Mar-83	6.7	11.6	87.2	7.3	10.7	87.0	7.0	5.3	0.40	19.14	1.53	7.97	0.26
20-Mar-83	6.6	13.0	88.6	7.0	11.2	87.0	7.0	5.4	0.48	21.47	3.31	15.40	0.15
27-Mar-83	6.2	12.4	87.7	6.8	11.1	87.2	6.9	5.7	0.39	19.05	2.09	10.99	0.19
03-Apr-83	5.3	12.2	88.0	7.1	11.4	87.3	6.9	6.7	0.35	16.07	1.17	7.30	0.30

APPENDIX D

SERIES OPERATION

During the period from February 13, 1983 through June 14, 1983, the two full scale dairy manure digesters were operated in series. The completely mixed reactor was fed daily, and its effluent was pumped to the plug flow digester. Table D-1 is a summary of the performance of the plug flow digester during this period of operation. The calculations presented in this Table assume that the system reactor volume was that of the plug flow reactor (93.5 m^3). Table D-2 is a similar summary of the completely mixed reactor, and Table D-3 contains the combined system performance results.

TABLE D-1. SUMMARY OF THE PLUG FLOW DIGESTER PERFORMANCE DURING THE PERIOD OF SERIES OPERATION.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S REMOVAL RATE (g/ℓ/d)	REMOVAL EFFICIENCY (%)	GAS/TVS (ℓ/g)
13-Feb-83	5.4	11.6	88.1	6.8	9.4	85.1	7.8	17.3	1.55	5.90	1.28	21.72	1.21
20-Feb-83	6.7	12.0	87.5	6.9	9.4	85.1	7.7	14.0	1.36	7.52	1.79	23.82	0.76
27-Feb-83	6.3	11.0	87.0	7.2	9.2	84.6	7.7	14.8	1.25	6.45	1.20	18.67	1.03
06-Mar-83	6.7	11.6	87.2	7.3	8.8	84.1	7.7	14.0	1.53	7.25	1.95	26.83	0.78
13-Mar-83	5.6	10.6	86.7	7.4	8.7	84.1	7.7	16.7	1.52	5.50	1.12	20.39	1.36
20-Mar-83	6.6	13.0	88.6	7.0	9.1	84.4	7.8	14.2	1.85	8.13	2.71	33.32	0.68
27-Mar-83	6.2	12.4	87.7	6.8	9.0	84.3	7.8	15.1	1.79	7.21	2.18	30.23	0.82
03-Apr-83	5.3	12.2	88.0	7.1	8.9	84.6	7.9	17.6	1.35	6.09	1.82	29.87	0.74
10-Apr-83	5.8	11.2	88.0	7.0	9.3	85.4	7.8	16.1	1.41	6.11	1.19	19.42	1.18
17-Apr-83	7.4	11.6	87.8	7.0	9.2	84.8	7.8	12.6	2.17	8.06	1.89	23.40	1.15
08-May-83	7.2	10.2	87.7	7.0	9.8	86.3	7.7	13.0	2.10	6.89	0.38	5.46	5.59

TABLE D-2. SUMMARY OF THE COMPLETELY MIXED DIGESTER PERFORMANCE RESULTS DURING THE PERIOD OF SERIES OPERATION.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	EFFLUENT TS (%)	EFFLUENT VS (%)	EFFLUENT pH	HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	TVS REMOVAL RATE (g/ℓ/d)	TVS REMOVAL EFFICIENCY (%)	TVS REMOVAL GAS/TVS (ℓ/g)
20-Feb-83	6.7	12.0	87.5	6.9	9.6	85.3	7.6	5.3	0.91	19.87	4.37	22.01	0.21
27-Feb-83	6.3	11.0	87.0	7.2	10.6	86.4	7.2	5.6	0.51	17.03	0.73	4.30	0.70
06-Mar-83	6.7	11.6	87.2	7.3	10.7	87.0	7.0	5.3	0.40	19.14	1.53	7.97	0.26
13-Mar-83	5.6	10.6	86.7	7.4	11.3	87.1	7.0	6.3	0.60	14.54	-1.04	-7.12	-0.58
20-Mar-83	6.6	13.0	88.6	7.0	11.2	87.0	7.0	5.4	0.48	21.47	3.31	15.40	0.15
27-Mar-83	6.2	12.4	87.7	6.8	11.1	87.2	6.9	5.7	0.39	19.05	2.09	10.99	0.19
03-Apr-83	5.3	12.2	88.0	7.1	11.4	87.3	6.9	6.7	0.35	16.07	1.17	7.30	0.30
10-Apr-83	5.8	11.2	88.0	7.0	11.3	87.6	6.9	6.1	0.40	16.15	-0.07	-0.43	-5.72
17-Apr-83	7.4	11.6	87.8	7.0	11.5	88.0	6.9	4.8	0.31	21.29	0.14	0.64	2.27
08-May-83	7.2	10.2	87.7	7.0	10.6	87.7	6.7	4.9	0.40	18.19	-0.71	-3.92	-0.56

TABLE D-3. SUMMARY OF THE SYSTEM PERFORMANCE DURING THE PERIOD OF SERIES OPERATION.

DATE	FLOW RATE (m^3/d)	INFLUENT TS (%)	INFLUENT VS (%)	INFLUENT pH	C M EFFLUENT TS (%)	C M EFFLUENT VS (%)	C M EFFLUENT pH	P F EFFLUENT TS (%)	P F EFFLUENT VS (%)	P F EFFLUENT pH	P F HRT (days)	BIOGAS (v/v/d)	TVS LOADING (g/ℓ/d)	T V S REMOVAL RATE (g/ℓ/d)	T V S REMOVAL EFFICIENCY (%)	T V S REMOVAL GAS/TVS (ℓ/g)
20-Feb-83	6.7	12.0	87.5	6.9	9.6	85.3	7.6	9.4	85.1	7.7	19.2	1.71	5.46	1.79	32.80	0.96
27-Feb-83	6.3	11.0	87.0	7.2	10.6	86.4	7.2	9.2	84.6	7.7	20.5	1.44	4.68	1.20	25.66	1.20
06-Mar-83	6.7	11.6	87.2	7.3	10.7	87.0	7.0	8.8	84.1	7.7	19.2	1.68	5.26	1.95	37.09	0.86
13-Mar-83	5.6	10.6	86.7	7.4	11.3	87.1	7.0	8.7	84.1	7.7	23.0	1.75	3.99	1.12	28.05	1.56
20-Mar-83	6.6	13.0	88.6	7.0	11.2	87.0	7.0	9.1	84.4	7.8	19.5	2.03	5.90	2.71	45.95	0.75
27-Mar-83	6.2	12.4	87.7	6.8	11.1	87.2	6.9	9.0	84.3	7.8	20.8	1.94	5.23	2.18	41.68	0.89
03-Apr-83	5.3	12.2	88.0	7.1	11.4	87.3	6.9	8.9	84.6	7.9	24.3	1.48	4.41	1.82	41.23	0.81
10-Apr-83	5.8	11.2	88.0	7.0	11.3	87.6	6.9	9.3	85.4	7.8	22.2	1.56	4.43	1.19	26.83	1.31
17-Apr-83	7.4	11.6	87.8	7.0	11.5	88.0	6.9	9.2	84.8	7.8	17.4	2.29	5.85	1.89	32.32	1.21
08-May-83	7.2	10.2	87.7	7.0	10.6	87.7	6.7	9.8	86.3	7.7	17.9	2.25	5.00	0.38	7.61	5.92

APPENDIX E

SUMMARY OF COGENERATOR SPECIFICATIONS AS SUPPLIED BY CUMMINS MOHAWK DIESEL, INC.

TABLE E-1

Engine	
Manufacturer:	White Engine, Inc.
Model:	D-2300 engine block and G-2300 head
Displacement:	3.70 liters (226 cubic inches)
Compression Ratio:	10 to 1
No. of Cylinders:	4 cylinders, in-line
Firing Order:	1-2-4-3
Cylinder Bore:	10.16 cm (4 inches)
Piston Stroke:	11.43 cm (4.5 inches)
Continuous Duty Power Rating:	36 kW at 1800 R.P.M. on natural gas
Generator	
Manufacturer:	KATO Engineering
Description:	Brushless, single bearing induction generator
Model No.:	25-480161111
Type No.:	21636
kW rating (continuous):	25 kW
kVA rating (continuous): 120/240	31.25 kVA Voltage:
Amperes:	130
Phase:	1 ϕ
Hz:	60
R.P.M.:	1800
Power Factor:	0.8
Continuous Duty Temperature Rise:	80°C
Design Ambient Temperature:	40°C
Insulation Class:	F
Wire:	4
Heat Recovery	
Exhaust:	Maxim Heat Recovery Silencer
Water Coolant:	Sen-Dure Water to Water Heat Exchanger

TABLE E-2. CONTROLS AND PROTECTION DEVICES

Type of Protection	Description of Equipment	Effect on Engine or Generator
Speed Control	American Bosch Electric Governor Control Unit, electric actuator and magnetic pickup	Hold engine R.P.M. at manually present level.
Overspeed		Shut engine down and close fuel solenoid valve at speeds above approximately 2100 R.P.M.
Low Coolant Level	Murphy sensor	Shut engine down and close fuel solenoid valve on low coolant level.
Low Oil Pressure	Murphy switch gauge	Shut engine down and close fuel solenoid valve at oil pressure less than 140 kPa.
High Coolant Temperature	1. Temperature activated fan and remote radiator[1]	Dumps excess heat if secondary water loop return exceeds 63°C.
	2. Temperature activated solenoid valve on secondary water loop[1]	Dumps hot water if secondary water loop return exceeds 66°C.
	3. Murphy switch gauge	Shuts engine down if primary engine coolant water exceeds 93°C.
Low Gas Pressure	Pressure sensor	Shuts engine down and closes fuel solenoid valve at pressures less than 0.5 kPa.
Inadequate Gas Supply	Pressure sensor and timer	At gas pressure in storage tanks of less than 140 kPa, generator's main breaker is opened; engine is run at no load for 5 minutes and then shut off[1].
Over Current Protection	Circuit breaker with shunt trip	Shunt trip opens breaker at current flow in excess of 150 amps resulting in generator shutdown.[2]
Prevent Generator from Motoring	Reverse power relay	Opens circuit breaker resulting in generator shutdown if reverse current flow occurs.[2]

[1]Modifications added by Cornell research group
[2]Later modifications by Cornell research group would allow engine to run for 5 minutes and then shut down for any reason that breaker tripped open.

APPENDIX F

DESCRIPTION OF MANURE FLOW, BIOGAS FLOW, WATER HEATING SYSTEM, AND COGENERATOR ELECTRICAL SYSTEM

DAIRY MANURE FLOW SCHEMATIC

(See Figure F-1)

1. ASTARC, Barn #2

   140 cow freestall barn
   Automatic flow scraping system.
   Minimal bedding used in this barn.

2. Collection Hopper Serviced by Hollow Piston Manure Transfer Pump

   Hydraulic ram hollow piston pump
   10 HP, 3 Ø, 1725 rpm electric motor driven
   Manufactured by Hedlund Manufacturing Co., Boyceville, WI

3. Feed Tank

   Short-term storage of manure prior to digesters.
   20' diameter, 16' deep cylindrical concrete tank

4. Feed Pump

   Transfers manure from feed tank to either anaerobic digester.
   Progressive cavity positive displacement pump.
   Driven by a 10 HP, 3 ϕ, 1760 rpm motor
   Manufactured by: Robbins & Meyers, Moyno Fluids Handling Products, Springfield, OH

5. Full Scale Completely Mixed Anaerobic Dairy Manure Fermentor

6. Mixing Pump

   Recirculates contents of the completely mixed reactor
   A rotary chopper pump driven by a 20 HP, 3 Ø, 1750 rpm electric motor
   Manufactured by: Vaughan Co. Inc., Montesamo, WA

7. Full Scale Plug Flow Anaerobic Dairy Manure Fermentor

8. Earthen Lagoon for Long-term Storage (175' x 100' x 15')

   Stores effluent from the reactors and undigested manures from the dairy complex prior to field application.

9. & 10. Short-term Digester Effluent Tank

   Captures digester effluent immediately after leaving the digester and facilitates in monitoring digester status.
   Eight foot diameter, 8' deep cylindrical tank of 1/4" steel construction.

11. Wasting Pump

Transfers mixed digester effluent to long-term manure storage.
Neoprene diaphragm pump
1 1/2 HP, 115 VAC, 1725 rpm electric motor driven
Manufactured by: ITT Marlow, Midland Park, NJ

12. Wasting Pump

Transfers plug flow effluent to long-term manure storage
3 HP centrifugal pump - vertical mount

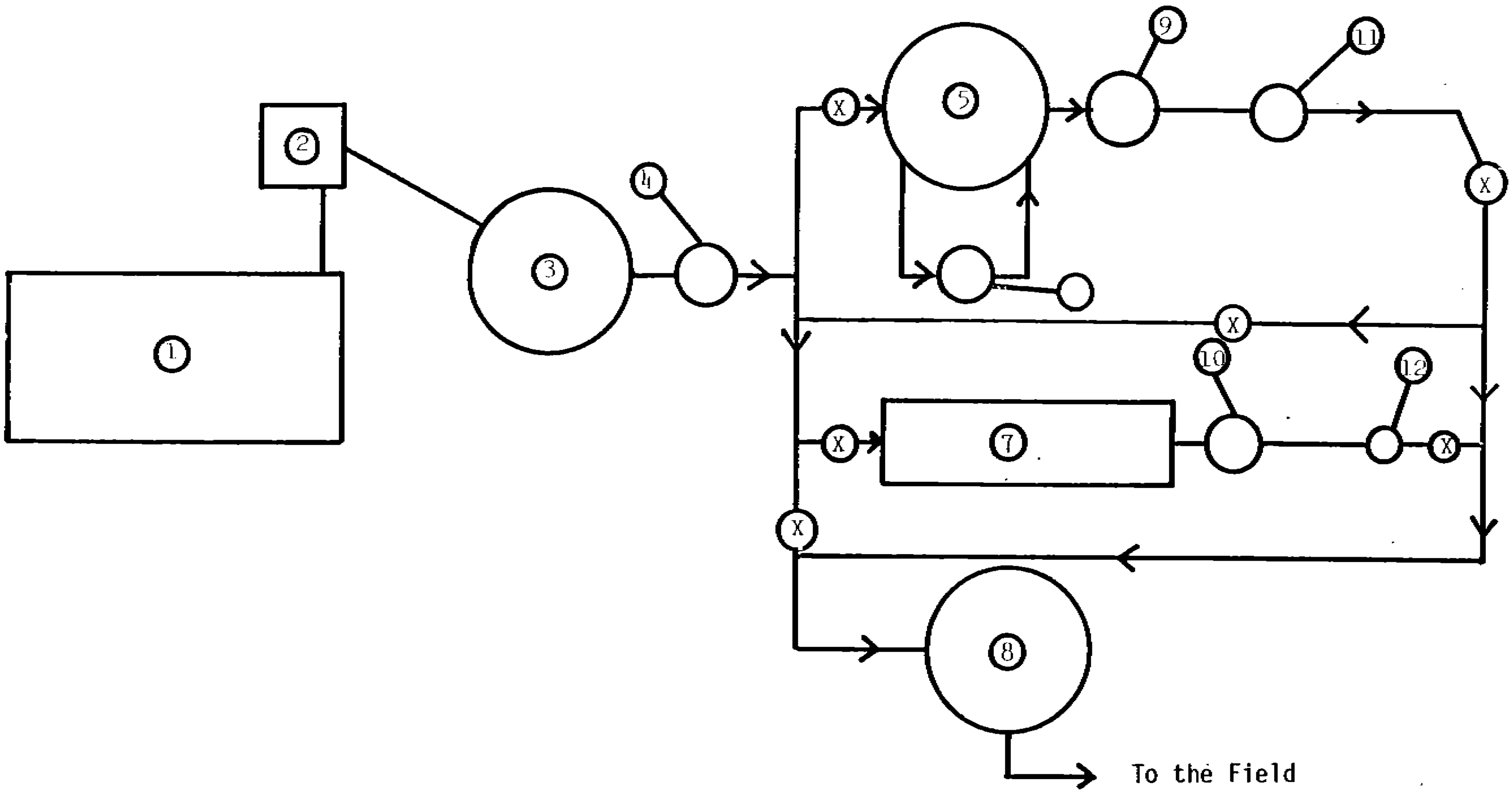

Figure F-1. A schematic of the dairy manure movement from Barn 2 of the ASTARC facility through the two full scale digesters and finally to the the field as final disposal.

BIOGAS COLLECTION SCHEMATIC

(See Figure F-2)

1. Full Scale Plug Flow Anaerobic Dairy Manure Fermentor

2. Full Scale Completely Mixed Anaerobic Dairy Manure Fermentor

3. Low Pressure Gas Storage Flexible Tank

   20' x 22' x 5' (when inflated)
   10,000 gallon capacity
   maximum pressure limit 1/2" psi
   operating pressure 1/2" W.C.

4. High Pressure Relief Mechanism

   Self-leveling water-containing device which allows biogas to vent to the atmosphere if the pipelines connecting the digesters and the low pressure storage tank pressurize to 2" WC.

5. Pressure Regulator

   Self-leveling water-containing device which functions as a particulate filter, condensation trap, and pressure regulator. Particulates are filtered from the biogas which must pass through a water bath. In conjunction, the biogas is cooled and water vapor is allowed to condense. The pressure regulator allows gas to flow only after it has reached a pressure greater than that exerted by the water column within.

6. Roots Gas Flow Meter

   Model 1.5M125TC
   Rated flow 1500 CFH
   1 1/4 inlet and outlet
   125 psi maximum operating pressure
   .25" WC minimum operating pressure (observed)

7. Low Pressure Compressor
   3/4 HP rotary vane compressor
   15 CFM rated delivery
   3 psi maximum operation pressure
   1500 rpm maximum operation speed
   automatic over pressure unloading device
   Manufactured by: Waukee Engineering Co. Inc., Milwaukee, WI

8. Diaphragm Gas Valve

   electromagnetic actuated diaphragm
   3 psi maximum operation pressure
   Manufactured by: Honeywell Inc., Minneapolis, MN

9. Gas Purifier

   Winslow biomass gas filter. Model No. #G1-GS3265-2.0
   Manufactured by: Winslow Filtration Products, Stoughton, WI

10. Medium Pressure Compressor

   7 1/2 HP, 220 VAC, 1 Ø motor driven
   Two-stage compressor
   Maximum outlet 515 psi
   Operating pressure 200 psi
   Maximum outlet flow 22 CFM
   Operating outlet flow 15 CFM

11. One-way check valve allows the two-stage compressor to automatically unload after compression is complete.

12. Pressure Cutoff Switch

   Pressure-activated mechanical contact switch
   Cuts power to compressors when pressure in lines exceeds 200 psi
   Manufactured by: Square D Co., Ashville, NC

13. Medium Pressure Storage Tanks

   200 psi operating pressure
   1,800 gallon capacity each
   3,600 gallon total medium pressure storage capacity

14. Compressor Activator Switching Mechanism

   Allows for manual or automatic activation of the compressors singularly or together.
   Equipped with time delay on switch to avoid contact or chatter.

   A magnetic starter allows current to flow to the compressors when it is activated. The magnetic starter is activated by a mercury switch mounted on a lever which is connected to the low pressure storage bag (LPS). As the LPS approaches maximum capacity, the level tilts, tripping the mercury switch, which activates the magnetic starter. The mercury switch disengages as the LPS is evacuated by the compressor(s).

15. Pressure Regulator

   Type 95L
   Operation 200 psi down to 2.5 psi
   Manufactured by: Fisher Controls, Marshal Town, IA

16. Pressure Regulator

   Type S201
   Operation 2.5 psi down to 11" WC
   Manufactured by: Fisher Controls, Marshal Town, IA

17. Pressure Regulator

    Operation 2.5 psi down to 3" - 9" WC
    Manufactured by: Fisher Controls, Marshal Town, IA

18. Gas to Water Heat Exchanger

    Cools biogas to 21°C
    28 inch long, 2' diameter, with 17 internal tubes
    Manufactured by: Sen-Dure, Syracuse, NY

19. Five-gallon Water Trap

20. Coalescing Filter

    Manufactured by: Paul Trinity, Cortland, NY

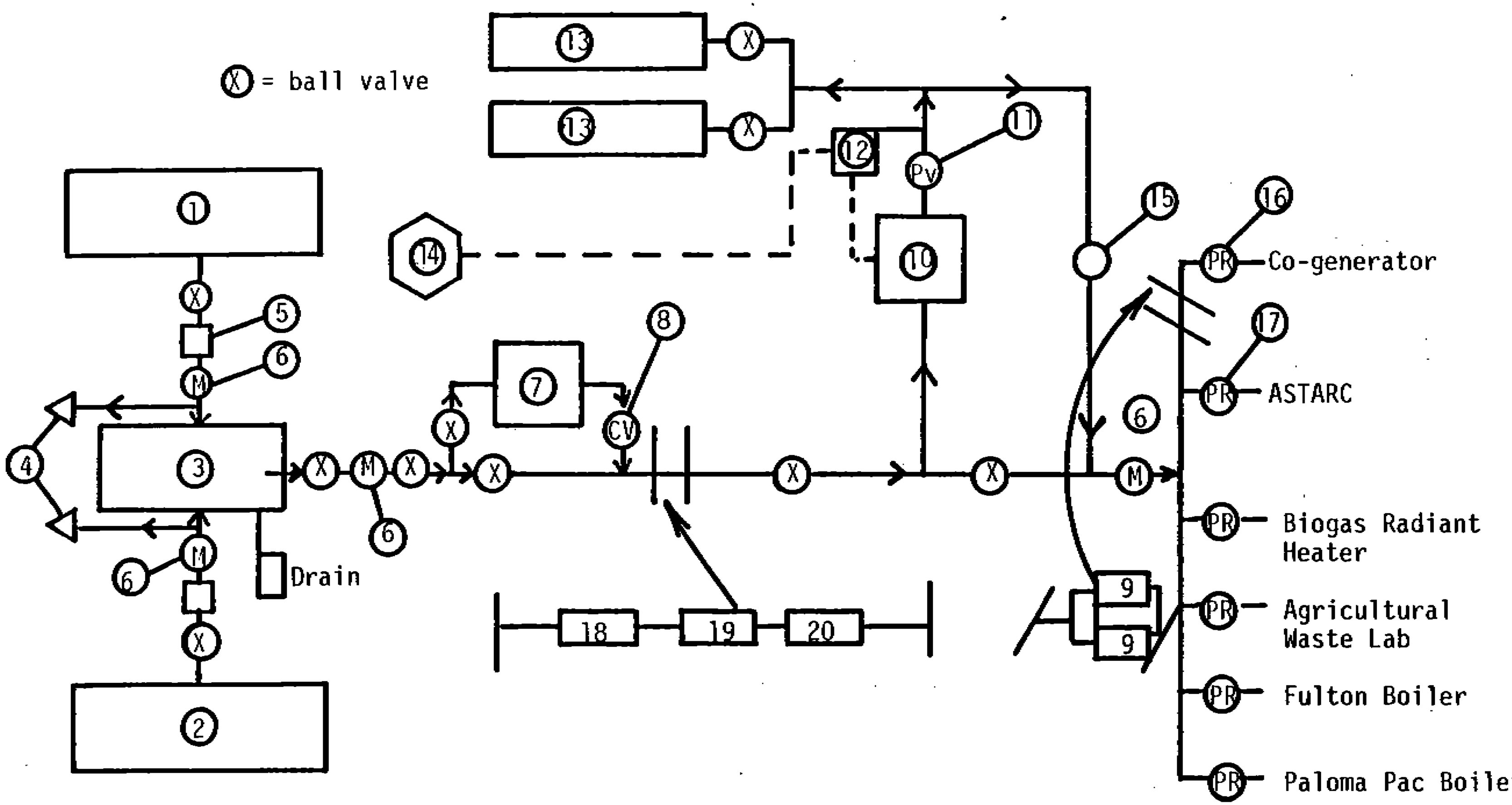

Figure F-2. Schematic of biogas collection, storage, and utilization system.

WATER HEATING SYSTEM FOR DIGESTERS AND HEAT RECOVERY SYSTEM FOR COGENERATOR

(See Figure F-3)

1. Cogenerator

(a) engine: 50 HP, 4 cylinder, White engine
spark ignition
226 cu. in.

(b) generator: 25 Kw, inductive type
operating at 240 VAC, 60 Hertz, and approximately 125 amp
single bearing
speed (nominal) 1800
power factor rating .80

Cogenerator package manufactured by Cummins-Mohawk Diesel Inc., Syracuse, NY

2. Heat Exchanger (water to water)

Inflow engine jacket cooling water 185°
Exchange capacity at 5 gpm
215,000 BTU/hr
Manufactured by: Sen-Dure Products Inc., Bay Shore, Long Island, NY

3. Heat Exchanger (gas to water)

Maximum heat recovery and engine silencer
Engine exhaust
168 CFM gas flow rate
Influent gas temperature @ 1200°F, exit temperature @ 450°F
At 5 gpm
215,000 BTU/hr recovery
Manufactured by: Riley-Beaird, Inc., Shreveport, LA

4. Heat Exchanger (water to water)

20 gpm cold water side — 5 gpm hot water side, 73°C
Cold water temperature 10°C assumed
125,000 BTU/hr recovery unit

5. Hot water storage tank

350 gal capacity
Glass-lined
Manufactured by: A.O. Smith, Auburn, NY

6. Expansion Tank

10 gal capacity
150 psi maximum pressure

7. Circulation Pump

   1/3 HP, 115 V, 7.2 amp
   1800 rpm
   20 gal/min flow

8. Expansion Tank

   15 gal capacity
   50 psi maximum pressure

9. 1/2" Solenoid Valve

   120 VAC
   12 Watt
   Manufactured by: Dayton Electric Mfg. Co., Chicago, IL

10. Mixing Valves

   Outflow range 130°F - 180°F
   Manufactured by Watts Regulator Co., Lawrence, MA

11. Full Scale Plug Flow Anaerobic Dairy Manure Fermentor

12. Full Scale Completely Mix Anaerobic Dairy Manure Fermentor

13, 14. Circulation Pumps (Bell & Gossett #60)

   1/4 HP, 1725 rpm
   115 VAC, 4.9 amp
   Flow capacity 12 gpm
   Manufactured by Bell & Gossett, Morton Grove, IL

15. Radiator

   Electric motor driven fan
   Remotely controlled by thermostatic relay

16. Fenwal Temperature Controller to control potable water circulation pump. On at 60°C, off at 43°C.

17. Circulation Pump

   1/5 HP, 3000 rpm, hot water circulation pump, 5 gpm
   Manufactured by March Mfg Inc., Glenview, IL

18. Pressure Regulator

   In cold make-up water line to the secondary circulation loop
   Drops water pressure from 70 psi to 12 psi

19. Fenwal Temperature Controller to control heat dump fan. Fan comes on as temperature above 63°C and shuts off at about 62°C.

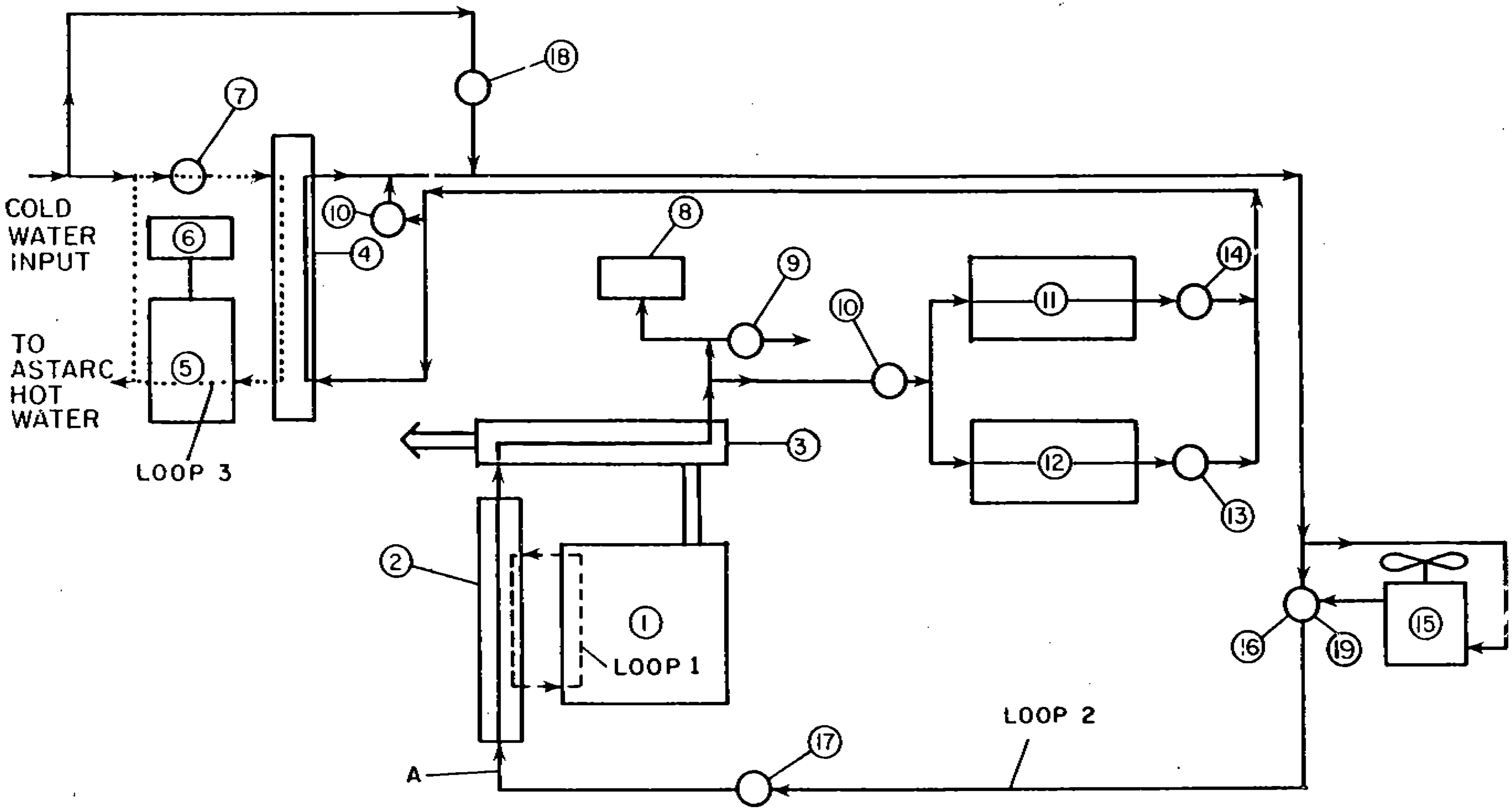

Figure F-3. Water heating system for digesters and heat recovery system for cogenerator.

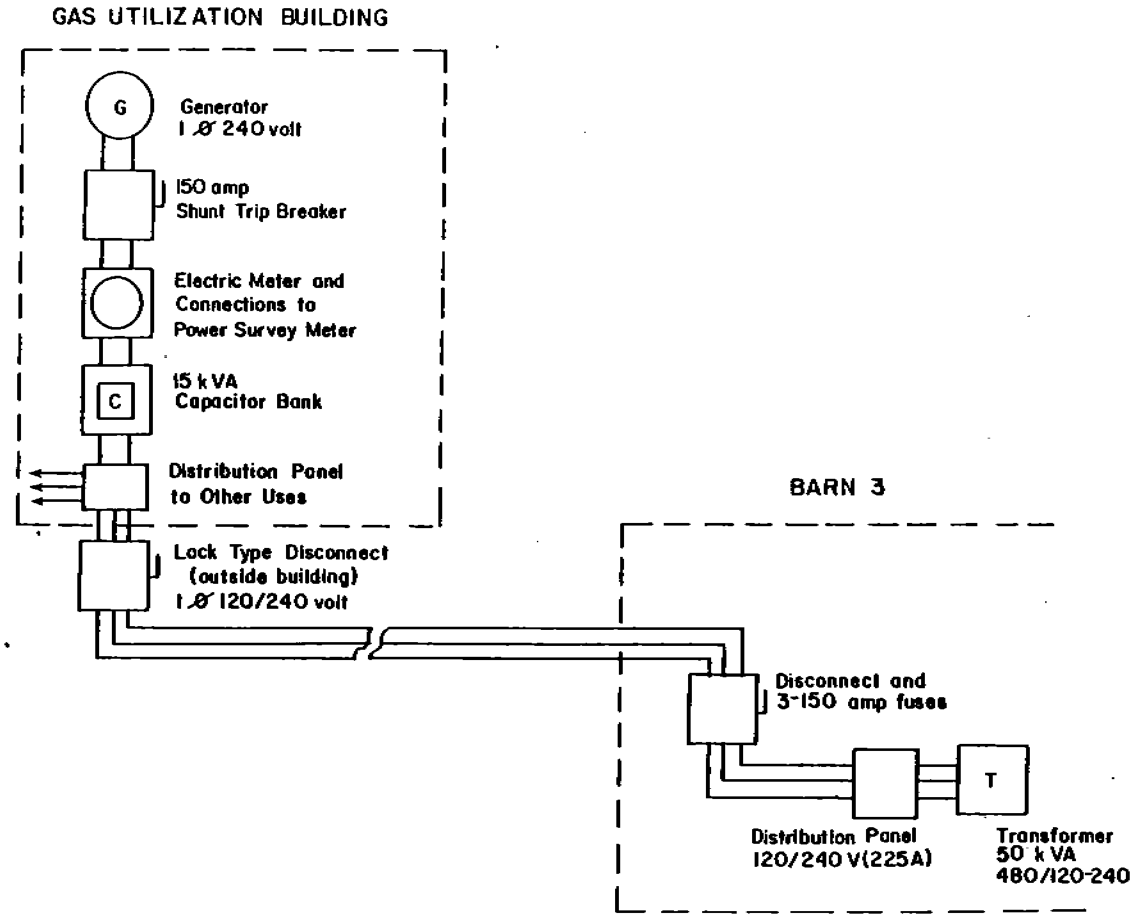

Figure F-4. Electrical diagram for cogeneration system at Cornell University Animal Science Teaching and Research Center, Harford, New York. (Generator includes reverse current monitoring equipment which will disconnect generator at breaker in reverse current situation.)

APPENDIX G

TEST PROCEDURE FOR COGENERATION UNIT

I. Pre-Trial Shakedown

Objective: This series of tests will be designed to check out the procedure for preparing the generator set for a test, collecting data, and evaluating the ability of the instruments to provide the desired information.

Pre-Test Preparation

1. Start and operate the engine generator set at approximately 25 kW output for a period of 15 minutes.

2. Adjust the engine generator set electrical output with engine speed control to the desired test level.

3. Adjust engine spark advance to the minimum advance which will obtain the highest.

4. Readjust electrical output to desired level by modifying engine speed. Recheck spark advance setting if major adjustment in electrical output was noted.

5. Allow engine to operate at this setting for 10 minutes prior to initiating data collection.

6. After all data is collected, adjust engine to desired new settings by means of speed control and spark advance setting. Allow engine to operate for 10 minutes before initiating next test.

Test Procedure: After the generator set has operated at the desired state for 10 minutes, data can be collected. Each test period will last 30 minutes. At the beginning and end of the test period, readings will be taken on all totalizing instruments (gas meter, BTU meter, water meters). All instantaneous measurements (pressure gauges, thermocouples, micromanometer, etc.) will be taken at three equally spaced intervals (beginning, middle, and end) during the test period. Trials will be conducted at three different loads of 10, 18, and 25 kW.

Measurements:

1. Environment factors (near engine air intake)
    a. Wet bulb temperature or humidity
    b. Dry bulb temperature
    c. Barometric pressure

2. Fuel use
   a. Volume of fuel consumed
   b. Pressure of fuel at gas meter
   c. Methane and carbon dioxide
   d. Temperature of fuel at gas meter

3. Air use
   a. Pressure drop across nozzle

4. Electrical output
   a. Record on strip chart of power survey meter: actual power and apparent power.
   b. Read power factor, apparent power, and accumulated electrical production from digital meters on power survey meter.

5. Heat Recovery
   a. Water flow rate of secondary loop through engine coolant and exhaust heat exchanger.
   b. Total BTU heat recovery of secondary loop through engine coolant and exhaust heat exchanger.
   c. Water temperatures on secondary water loop before and after engine coolant heat exchanger and exhaust heat exchanger.
   d. Exhaust gas temperature before and after exhaust heat exchanger.

6. Engine parameters
   a. RPM
   b. Oil temperature
   c. Exhaust gas temperature before and after exhaust heat exchanger
   d. Spark timing
   e. Engine coolant temperature at rated load

II. Spark System Parameters

Objective: Determine the importance of various spark system parameters on smooth operation of the engine.

Pre-Test Preparation: Same as used for pre-trial shakedown with the exception that 5 minute intervals are used to allow unit to attain steady state conditions.

Test Procedure: Three different spark plugs (Champion J-6, J-8, and RJ-10) will be tested at a plug gap of 0.076 cm. The J-8 plug will also be checked at a gap of 0.043 cm. Each plug and gap will be run at loads ranging from 5 to 25 kW at 5 kW intervals and at a lean and rich fuel-air mixture. For a few tasks, spark timing will also be varied from its desired level to determine:

Measurements:

1. Timing of engine
2. Actual power output of engine
3. Strip chart recording of actual and apparent power output versus time. This is used to help determine smoothness of engine operation.
4. Audio observation at engine exhaust.

Desired Final Output:

1. Effect of spark timing, plug selection and gap selection on smoothness of engine operation.
2. Indication of a desirable level of spark timing for various loads and fuel-air mixtures.

III. Performance at Varying Air-Fuel Mixtures at Rated Load

Objective: These tests will be designed to determine the effect of fuel-air mixture on engine generator set performance and to locate the point of optimum efficiency at rated load.

Pre-Test Preparation: The carburetor fuel jet will be adjusted to allow an appropriate fuel-air mixture. The speed control will be set to allow operation at rated electrical output. The pre-test preparation procedure will remain the same as used in Pre-Trial Shakedown after a fuel air mixture and speed setting is selected.

Test Procedure: The engine will be operated at 10 different fuel-air settings. All remaining test procedures will follow those established in a Pre-Trial Shakedown.[1] All thermal efficiency measurements will be made at rated loads. A short check will also be made of maximum power output at each carburetor setting.

Measurements: Same as Pre-Trial Shakedown

Desired Final Output:

1. Maximum power output versus fuel-air ratio
2. Fuel efficiency conversion to electricity versus fuel-air ratio
3. Fuel efficiency conversion to hot water versus fuel-air ratio.

IV. Co-generator Performance at Various Loads

Objective: This series of tests will be designed to define generator and heat recovery performance at various electrical outputs.

Pre-Test Preparation: The procedure for preparing the engine-generator set for each test will remain the same as discussed in the Pre-Trial Shakedown. Three fuel-air mixture settings will be selected for these tests.

Test Procedure: Tests will be conducted at 2.5 kW load intervals between 5 and 25 kW electrical output. The procedure for these tests will be the same as discussed in Pre-Trial Shakedown.[1]

Measurements: Same as in Pre-Trial Shakedown

Desired Final Output:

1. Efficiency of conversion process from biogas to electricity
2. Efficiency of conversion process from biogas to hot water for both heat exchangers
3. Maximum generator electrical output
4. Generator characteristics: power factor, slip, reactive power requirements.

V. Effect of Compression Ratio on Cogenerator Performance. This series of tests will be a repeat of No. III, "Cogenerator Performance at Various Loads" only at different compression ratios. Hopefully a compression ratio of approximately 8 to 1 and 14 to 1 can be tested.[2]

VI. Effect of Capacitators on Power Factor

Objectives: Since capacitance losses create a leading power factor, they will counter the lagging power factor of the generator. With the addition of a capacitor bank, generator characteristics will be checked.

Pre-Test Preparation: Same as Pre-Trial Shakedown except only 5 minute intervals between tests to allow steady state conditions to be attained.

Test Procedure: Generator will be operated at loads ranging from 5 kW to 25 kW at 2.5 kW intervals. Tests will last approximately 5 minutes during which appropriate measurements are made.

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[1]Length of test period was changed from 30 to 60 minutes.
[2]Not completed

Measurements:

1. Engine
   a. rpm
2. Generator
   a. Actual power
   b. Apparent power
   c. Power factor

Desired Final Output: Generator characteristics versus actual power output of generator.

VII. Long-Term Engine Performance

Objective: This series of tests will provide information on operating procedures, maintenance schedules, and operating cost of our cogenerator. The value of gas scrubbing of sulfur compounds will also be monitored.

Pre-Test Preparation: Establish a maintenance procedure for all necessary components (plugs, valve adjustment, air cleaner, etc.). Establish an oil testing program schedule.

Test Procedure: The engine generator set will be operated at or near 25 kW power output for two separate test periods of 1600 hours. During the initial test period, raw biogas will be fed directly to the engine. The second test period will utilize the biogas which has passed through a Winslow gas conditioner.

Measurements:

1. Regular samples of biogas will be collected and monitored for methane, carbon dioxide, and hydrogen sulfide.
2. Weekly readings of electrical production, cogenerator BTU production, dairy consumption, digester BTU consumption, dairy hot water use, and total operating hours of digester.
3. Logs will be kept of all maintenance items and costs.
4. Oil samples will be collected regularly and analyzed. A 250-hour oil change interval will be used at least once for each test period. During this period, oil samples will be collected at 50-hour intervals. During the remainder of the test, samples will be collected at the time the oil is changed.
5. Engine head and oil pan will be removed at the end of each test to allow observation of any deposits, wear, or other problems associated with the fuel.
6. Spark plugs will be removed regularly for observation of any deposits and to allow compression testing of all cylinders.

APPENDIX H
SUMMARIES OF ENGINE FAILURE AND BIOGAS FILTER ANALYSES

ENGINE FAILURE ANALYSIS *(Span and Teprag, 1983)

The following summarizes the results of the engine failure analysis conducted by the manufacturer. The objective of their review was to determine the cause of failure of a D-2300 engine operating on biogas fuel at Cornell University (25 kw generator set with 2505 hours of operation).

The primary engine failure occurred at the wrist pin bushing of the #2 connecting rod. The connecting rod bolt fracture and the connecting rod fracture at #2 cylinder were secondary failures. The copper lining of the bushing was destroyed to the steel back. This appeared to result from lube oil contamination and degradation.

Metallurgical testing of the crankshaft, camshaft, connecting rod and cap, connecting rod bolts, wrist pin, and valve tappets revealed conformance with the engineering specifications.

The rod bearings and main bearings had flaking, pitting, numerous deep scratches, and debris caused by fatigue of other components. Tappets had severe wear on the contact face in a circular pattern. The camshaft lobes exhibited signs of wear at the base radius through the ramp and flank, with most severe wear in the form of flat spots across the nose. Heavy signs of wear also existed on the camshaft drive gear for the oil pump at the drive side of all teeth.

The results show that failure resulted from wrist pin bushing deterioration at #2 cylinder. The remaining connecting rod bushings exhibited the same loss of copper liner material as noted at the #2 rod location. Extreme clearance at the wrist pin and bushing was attributed to the effects of corrosive action of contaminants present in the biogas fuel used in this application. Lube oil samples were not available; therefore, the degree of contamination was not evaluated. However, the extreme wear observed on all component parts supports the conclusions of lube oil contamination.

The attachment shows two views each of the connecting rod and cap involved in this failure.

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*Span, T. and Teprag, T. Personal communication to Cummins Mohawk Diesel, Inc., Syracuse, New York, by White Engines, Inc. September 19, 1983.

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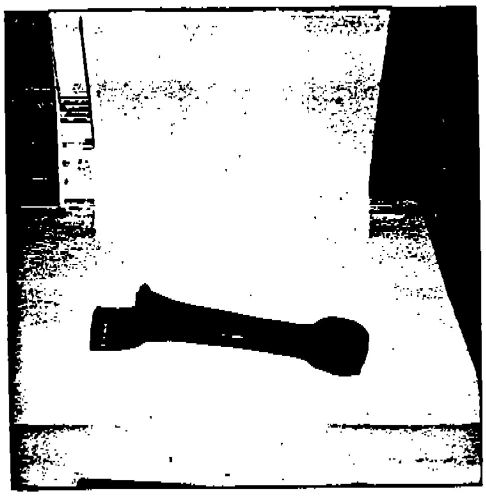
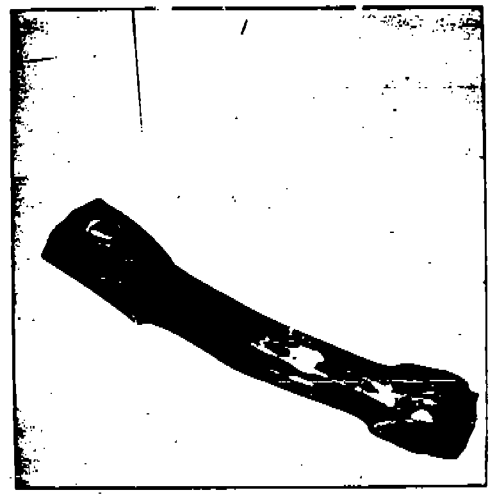
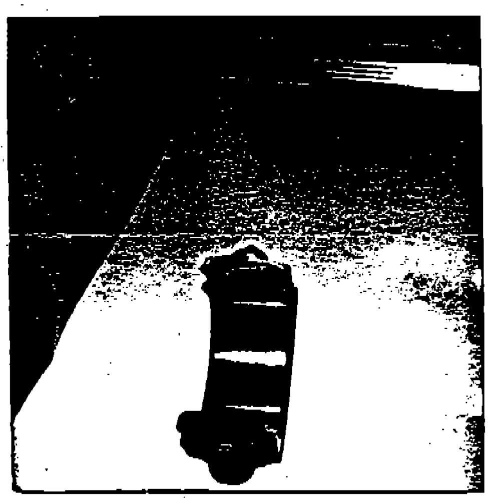




#2 FAILED CONNECTING ROD



#2 CONNECTING ROD CAPS

BIOGAS FILTER ANALYSIS *(Bacher, 1983)

The biogas filter was analyzed after engine failure to determine the degree of depletion of the filter. Since it is difficult to ascertain the degree of depletion of the filter, the Winslow filter was evaluated by the manufacturer.

The elements of the Winslow filter must be changed where the base chemical pH is decreased from a new pH of greater than 10.25 to 8.25. The pH of the unit was 8.32, thus indicating that there was some remaining treatment capacity.

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*Bacher, J.F. Personal communication to R.K. Koelsch from Winslow Filter Division, Nelson Industries. September 27, 1983.

APPENDIX I
ORIGINAL DATA FOR SHORT-TERM PERFORMANCE TESTS

TABLE I-1. ORIGINAL DATA FOR SHORT TERM PERFORMANCE TESTS

Measurements	Units								
Carburetor Setting	-	5	5	5	5	5	5	5	5
Desired Electrical Load	kW	5.0	7.5	10.0	12.5	15.0	17.5	20.0	22.5
Environmental Factors									
a) Corrected Barometric Pres.	in. Hg	28.75	28.75	28.74	28.69	28.92	28.86	28.88	28.66
b) Wet Bulb Temp.	°F	68	66	69	71	78	65	64	63
c) Dry Bulb Temp.	°F	87	87	86	89	109	82	78	86
Air Consumption									
a) Nozzle Coefficient	-	0.957	0.960	0.962	0.965	0.966	0.970	0.972	0.970
b) Specific Vol. of Air	ft^3/lb da	14.59	14.55	14.59	14.72	15.18	14.38	14.26	14.52
c) Pres. Drop Across Nozzle	in. H_2O	0.277	0.370	0.461	0.758	0.855	1.186	1.668	1.779
d) Airflow Rate	lb da/hr	121	141	157	201	211	256	306	312
Fuel Consumption									
a) % Methane	%	58	58	58	59	59	59	59	58
b) Biogas Consumption	ft^3/min	4.60	5.18	5.90	6.63	7.36	8.23	8.90	9.87
c) Methane Consumption	lb/hr	6.67	7.50	8.54	9.77	10.8	12.1	13.1	14.3
d) Air-Fuel Ratio	-	18.2	18.8	18.9	20.6	19.3	21.1	23.3	21.8
e) Equivalence Ratio	-	0.95	0.91	0.91	0.83	0.89	0.81	0.74	0.79
Energy Balance									
a) Energy Consumption	BTU/min	2390	2690	3070	3500	3890	4350	4700	5130
b) Electrical Production	BTU/min	296	440	570	730	840	980	1170	1270
c) Exhaust Heat Recovery	BTU/min	330	370	490	610	710	720	786	950
d) Engine Coolant Heat Recovery	BTU/min	1000	1040	1110	1210	1160	1200	1220	1100
Electrical Characteristics									
a) Actual Power	kW	5.2	7.8	10.0	12.9	14.8	17.3	20.5	22.4
b) Apparent Power	kVa	14	16	18	21	24	26.5	31	33
c) Power Factor (lagging)	%	0.36	0.47	0.55-0.56	0.60-0.61	0.63	0.65	0.66	0.66
Other									
a) Spark Timing	°BTDC	27	27	28	34	35			
b) Engine RPM	RPM	1804	1806	1809	1813	1815	1818	1824	1827
c) Coolant Temp.	°F	180	180	180	176	185	184	198	180
d) Exhaust Temp. Before H.E.	°F	941	971	1028	1115	1040	983	1003	969
After H.E.	°F	248	272	299	353	355	348	387	903
e) Heat Recovery Loop Temp.									
Before Coolant H.E.	°F	141	139	137	139	141	148	151	141
Between H.E.'s	°F	162	161	161	164	166	169	181	164
After Exhaust H.E.	°F	169	169	172	177	182	187	200	184
f) Water Flow Rate through H.E.	gal/hr	343	343	341	331	339	411	310	347

H.E. - heat exchanger

TABLE I-2. ORIGINAL DATA FOR SHORT TERM PERFORMANCE TESTS

Measurements	Units								
Carburetor Setting	-	4	4	4	4	4	4	4	4
Desired Electrical Load	kW	5	7.5	10.0	12.5	15.0	17.5	20.0	22.5
Environmental Factors									
a) Corrected Barometric Pres.	in. Hg	28.75	28.82	28.74	28.76	28.72	28.72	28.73	28.73
b) Wet Bulb Temp.	°F	69	71	70	60	76	74	71	73
c) Dry Bulb Temp.	°F	89	76	92	80	91	98	92	97
Air Consumption									
a) Nozzle Coefficient	-	0.958	0.961	0.964	0.967	0.968	0.969	0.971	0.971
b) Specific Vol. of Air	ft^3/lb da	14.64	14.38	14.73	14.33	14.85	14.96	14.76	14.91
c) Pres. Drop Across Nozzle	in. H_2O	0.288	0.400	0.625	0.810	0.939	1.132	1.297	1.556
d) Airflow Rate	lb da/hr	123	147	183	211	224	245	265	289
Fuel Consumption									
a) % Methane	%	58	59	59	59	60	60	60	60
b) Biogas Consumption	ft^3/min	4.87	5.81	6.70	7.65	7.82	8.76	9.35	10.11
c) Methane Consumption	lb/hr	7.05	8.56	9.87	11.3	11.7	13.1	14.0	15.1
d) Air-Fuel Ratio	-	17.5	18.0	18.5	18.7	19.1	18.7	18.9	19.1
e) Equivalence Ratio	-	0.983	0.956	0.93	0.92	0.90	0.92	0.91	0.90
Energy Balance									
a) Energy Consumption	BTU/min	2530	3070	3540	4110	4210	4720	4030	5430
b) Electrical Production	BTU/min	280	430	600	730	940	1040	1180	1300
c) Exhaust Heat Recovery	BTU/min	310	450	440	670	720	800	840	960
d) Engine Coolant Heat Recovery	BTU/min	1000	1090	1210	1170	1200	1270	1340	1410
Electrical Characteristics									
a) Actual Power	kW	4.9	7.6	10.5	12.8	16.6	18.3	20.7	22.8
b) Apparent Power	kVa	14-15	15-16	18-19	21	26	28	31	34
c) Power Factor (lagging)	%	0.34	0.48	0.57	0.60	0.64	0.65	0.66	0.66
Other									
a) Spark Timing	°BTDC	27	31	33	34	35	35	37	37
b) Engine RPM	RPM	1804	1807	1810	1812	1817	1822	1826	1830
c) Coolant Temp.	°F	180	180	180	176	185	185	185	185
d) Exhaust Temp. Before H.E.	°F	938	985	989	1054	1037	1081	1081	1089
After H.E.	°F	247	283	297	322	344	368	378	401
e) Heat Recovery Loop Temp.									
Before Coolant H.E.	°F	140	135	134	137	142	139	138	136
Between H.E.'s	°F	162	158	158	158	166	166	166	166
After Exhaust H.E.	°F	168	167	167	170	183	183	184	186
f) Water Flow Rate through H.E.	gal/hr	343	340	342	401	345	345	345	344

H.E. - heat exchanger

TABLE I-3. ORIGINAL DATA FOR SHORT TERM PERFORMANCE TESTS

Measurements	Units								
Carburetor Setting	-	3	3	3	3	3	3	3	3
Desired Electrical Load	kW	5	7.5	10.0	12.5	15.0	17.5	20.0	22.5
Environmental Factors									
a) Corrected Barometric Pres.	in. Hg	28.86	28.85	28.88	28.83	28.82	28.81	28.70	28.85
b) Wet Bulb Temp.	°F	70	67	71	68	70	69	70	72
c) Dry Bulb Temp.	°F	92	94	90	95	98	99	86	85
Air Consumption									
a) Nozzle Coefficient	-	0.959	0.961	0.964	0.964	0.965	0.967	0.969	0.971
b) Specific Vol. of Air	ft^3/lb da	14.69	14.66	14.63	14.74	14.83	14.83	14.63	14.58
c) Pres. Drop Across Nozzle	in. H_2O	0.325	0.399	0.562	0.568	0.703	0.835	1.084	1.445
d) Airflow Rate	lb da/hr	131	146	174	174	193	211	243	281
Fuel Consumption									
a) % Methane	%	59	59	59	59	59	59	59	59
b) Biogas Consumption	ft^3/min	4.46	6.29	7.30	7.75	8.51	9.48	11.0	12.5
c) Methane Consumption	lb/hr	8.04	9.27	10.8	11.5	12.5	14.0	16.2	18.4
d) Air-Fuel Ratio	-	16.2	15.8	16.0	15.5	15.5	15.1	15.0	15.3
e) Equivalence Ratio	-	1.06	1.09	1.08	1.11	1.11	1.14	1.14	1.13
Energy Balance									
a) Energy Consumption	BTU/min	2890	3330	3860	4120	4500	5010	5830	6610
b) Electrical Production	BTU/min	310	390	580	730	850	990	1110	1310
c) Exhaust Heat Recovery	BTU/min	520	590	690	690	770	800	900	990
d) Engine Coolant Heat Recovery	BTU/min	1080	1160	1210	1220	1250	1300	1350	1440
Electrical Characteristics									
a) Actual Power	kW	5.5	6.8	10.2	12.9	15.0	17.4	19.6	23.1
b) Apparent Power	kVa	14-15	15-16	18	20-21	23	26	29	35
c) Power Factor (lagging)	%	0.35	0.45	0.55	0.60	0.63	0.65	0.66	0.66
Other									
a) Spark Timing	°BTDC	30	31	33	34	36	38	40	48
b) Engine RPM	RPM	1804	1806	1809	1812	1815	1819	1822	1833
c) Coolant Temp.	°F	176	168	175	180	182	187	180	185
d) Exhaust Temp. Before H.E.	°F	1170	1209	1218	1185	1198	1203	1222	1187
After H.E.	°F	303	325	354	359	379	401	439	463
e) Heat Recovery Loop Temp.									
Before Coolant H.E.	°F	134	138	131	139	137	143	134	134
Between H.E.'s	°F	157	162	157	164	161	171	163	166
After Exhaust H.E.	°F	168	174	171	179	176	188	183	188
f) Water Flow Rate through H.E.	gal/hr	339	340	335	336	331	327	326	323

H.E. - heat exchanger